CREDIT SUISSE

03 January 2012
Global
Equity Research
Energy (Integrated Oil & Gas) / MARKET WEIGHT

Energy in 2012

Research Analysts

Edward Westlake
212 325 6751
edward.westlake@credit-suisse.com

Brad Handler
212 325 0772
brad.handler@credit-suisse.com

Yves Siegel, CFA
212 325 8462
yves.siegel@credit-suisse.com

Dan Eggers, CFA
212.538.8430
dan.eggers@credit-suisse.com

Mark Lear, CFA
212 538 0239
mark.lear@credit-suisse.com

Arun Jayaram, CFA
212 538 8428
arun.jayaram@credit-suisse.com

Kim Fustier
44 20 7883 0384
kim.fustier@credit-suisse.com

Jason Turner
44 20 7888 1395
jason.turner@credit-suisse.com

Thomas Adolff
44 20 7888 9114
thomas.adolff@credit-suisse.com

David Hewitt
65 6212 3064
david.hewitt.2@credit-suisse.com

Sandra McCullagh
61 2 8205 4729
sandra.mccullagh@credit-suisse.com

Andrey Ovchinnikov
7 495 967 8360
andrey.ovchinnikov@credit-suisse.com

Emerson Leite, CFA
55 11 3841 6290
emerson.leite@credit-suisse.com

Brian Dutton
416 352 4596
brian.dutton@credit-suisse.com

Mark Henderson
+44 20 7883 6901
mark.henderson.2@credit-suisse.com

Gregory Lewis, CFA
212 325 6418
gregory.lewis@credit-suisse.com

COMMENT

Transitions

Exhibit 1: **Transitions**

Source: Credit Suisse Research.

- **An Uncertain World:** As we head into 2012, much uncertainty remains within the global macro environment. Although our macro indicators signal continued sluggishness early in 2012, we remain positive on 2013-2014 Brent Oil prices—supply remains a significant constraint and secular trends in non-OECD demand are supportive. Entering 2012, we find Energy fairly valued versus other market sectors. Within Energy, we lower our weighting on the Integrated Oils to Market Weight. We believe there will be a rotation into Oilfield Services and select liquid-rich E&Ps.

- **Transitions to Watch in 2012:** With technology change and political/ regulatory volatility, there are a lot of transitions to watch. We believe there will be greater M&A activity from the Majors and from Asia, with a focus on shales and exploration hotspots. Within US E&P, we focus on successful liquid transition stories. The Eagleford, Mississippian, core Niobrara, and liquids-rich Marcellus top the 2012 returns leaderboard. US Oilfield Services suffered from execution issues in 2011, leaving the shares looking undervalued. Strong demand for services and better execution in 2012 offer upside potential. Internationally, we are cautious on Russian Energy, positive on YPF, and believe Asia's upstream companies will outperform local peers. On the political front, several transitions in key oil suppliers make us nervous.

- **Some Transitions That Look Farther Off:** We devote a considerable part of this report to analyses of US gas markets. We lower the outlook for demand from the power sector, offering a detailed analysis of energy efficiency. On the supply side, we highlight drilling efficiency gains as a cap on US gas prices, even when power and LNG export demand eventually inflects higher.

DISCLOSURE APPENDIX CONTAINS IMPORTANT DISCLOSURES, ANALYST CERTIFICATIONS, INFORMATION ON TRADE ALERTS, ANALYST MODEL PORTFOLIOS AND THE STATUS OF NON-U.S ANALYSTS. FOR OTHER IMPORTANT DISCLOSURES, visit www.credit-suisse.com/ researchdisclosures or call +1 (877) 291-2683. U.S. Disclosure: Credit Suisse does and seeks to do business with companies covered in its research reports. As a result, investors should be aware that the Firm may have a conflict of interest that could affect the objectivity of this report. Investors should consider this report as only a single factor in making their investment decision.

Exhibit 2: Credit Suisse Global Energy Research

United States		
Integrated Oils & Refiners		
Ed Westlake (New York)	+1 212-325 6751	edward.westlake@credit-suisse.com
Rakesh Advani (New York)	+1 212 538 5084	rakesh.advani@credit-suisse.com
Exploration & Production		
Arun Jayaram (New York)	+1 212 538 8428	arun.jayaram@credit-suisse.com
Mark Lear (New York)	+1 212 538 0239	mark.lear@credit-suisse.com
David Lee (New York)	+1 212 325 6693	david.lee@credit-suisse.com
David Yedid (New York)	+1 212 325 1831	david.yedid@credit-suisse.com
Brittney Abbott (New York)	+1 212 325 1716	brittney.abbott@credit-suisse.com
Oil Services		
Brad Handler (New York)	+1 212 325 0772	brad.handler@credit-suisse.com
Eduardo Royes (New York)	+1 212 538 7446	eduardo.royes@credit-suisse.com
Jonathan Sisto (New York)	+1 212-325-1292	jonathan.sisto@credit-suisse.com
Kristin Cummings (New York)	+1 212-325-1318	kristin.cummings@credit-suisse.com
MLPs		
Yves Siegel (New York)	+1 212 325 8462	yves.siegel@credit-suisse.com
Brett Reilly (New York)	+1 212 538 3749	brett.reilly@credit-suisse.com
Pooja Shakya (New York)	+1 212 535 2827	pooja.shakya@credit-suisse.com
Utilities		
Dan Eggers (New York)	+1 212 538 8430	dan.eggers@credit-suisse.com
Kevin Cole (New York)	+1 212 538 8422	kevin.cole@credit-suisse.com
Matt Davis (New York)	+1 212 325 2573	matthew.davis@credit-suisse.com
Katie Chapman (New York)	+1 212 325 1261	katie.chapman@credit-suisse.com
Alternative Energy		
Satya Kumar (San Francisco)	+1 415 249 7928	satya.kumar@credit-suisse.com
Ed Westlake (New York))	+1 212-325 6751	edward.westlake@credit-suisse.com
Patrick Jobin (New York)	+1 212 325 0843	patrick.jobin@credit-suisse.com
Specialist Sales		
Tom Marchetti (New York)	+1 212 325 0667	thomas.marchetti@credit-suisse.com
Charlie Balancia (New York)	+1 212-325 6314	charles.balancia@credit-suisse.com
Commodities		
Jan Stuart (New York)	+1 212 325 1013	jan.stuart@credit-suisse.com
Stefan Revielle (New York)	+1 212 538 6802	stefan.revielle@credit-suisse.com
Joachim Azria (New York)	+1 212 325 4556	joachim.azria@credit-suisse.com
Canada		
Brian Dutton (Toronto)	+1 416 352 4596	brian.dutton@credit-suisse.com
Andrew Kuske (Toronto)	+1 416 352 4561	andrew.kuske@credit-suisse.com
Courtney Morris (Toronto)	+1 416 352 4595	courtney.morris@credit-suisse.com
Paul Tan	+1 416 352 4593	paul.tan@credit-suisse.com
Jason Frew (Calgary)	+1 403 476 6022	jason.frew@credit-suisse.com
Terence Chung (Calgary)	+1 403 476 6024	terence.chung@credit-suisse.com
David Phung (Calgary)	+1 403 476 6023	david.phung@credit-suisse.com
Russia/Emerging Europe		
Oil & Gas		
Mark Henderson (London)	+44 20 7883 6901	mark.henderson.2@credit-suisse.com
Andrey Ovchinnikov (Moscow)	+7 495 967 8360	andrey.ovchinnikov@credit-suisse.com
Chech Republic and Poland Utilities		
Piotr Dzieciolowski (Warsaw)	+48 22 526 5638	piotr.dzieciolowski@credit-suisse.com
Turkish Oil Refiners		
Onur Muminoglu (Istanbul)	+90 212 349 0454	onur.muminoglu@credit-suisse.com
Europe		
Integrated Oils & Refiners		
Kim Fustier (London)	+44 20 7883 0384	kim.fustier@credit-suisse.com
Thomas Adolff (London)	+44 20 7888 9114	thomas.adolff@credit-suisse.com
Charlotte Elliott (London)	+44 20 7888 9484	charlotte.elliott@credit-suisse.com
Exploration & Production		
Ritesh Gaggar (London)	+44 20 7888 0277	ritesh.gaggar@credit-suisse.com
Arpit Harbhajanka (London)	+44 20 7888 0151	arpit.harbhajanka@credit-suisse.com
Thomas Adolff (London)	+44 20 7888 9114	thomas.adolff@credit-suisse.com
Oil Services		
Ritesh Gaggar (London)	+44 20 7888 0277	ritesh.gaggar@credit-suisse.com
Jason Turner (London)	+44 20 7888 1395	jason.turner@credit-suisse.com
Utilities		
Vincent Gilles (London)	+44 20 7888 1926	vincent.gilles@credit-suisse.com
Mark Freshney (London)	+44 20 7888 0887	mark.freshney@credit-suisse.com
Michel Debs (London)	+44 20 7883 9952	michel.debs@credit-suisse.com
Mulu Sun (London)	+44 20 7888 0269	mulu.sun@credit-suisse.com
Zoltan Fekete (London)	+44 20 7888 0285	zoltan.fekete@credit-suisse.com
Specialist Sales		
Jason Turner (London)	+44 20 7888 1395	jason.turner@credit-suisse.com
Mark Whitfeld (London)	+44 20 7888 8038	mark.whitfeld@credit-suisse.com
Latin America		
Oil & Gas		
Emerson Leite (Sao Paulo)	+55 11 3841 6290	emerson.leite@credit-suisse.com
Andre Sobreira (Sao Paulo)	+55 11 3841 6299	andre.sobreira@credit-suisse.com
Utilities		
Vinicius Canheu (Sao Paulo)	+55 11 3841 6310	vinicius.canheu@credit-suisse.com
Adelia Souza (Sao Paulo)	+55 11 3841 6323	adelia.souza@credit-suisse.com
Ethanol, Agribusiness and Transportation		
Luiz Campos (Sao Paulo)	+55 11 3841 6312	luiz.campos@credit-suisse.com
Viccenzo Paternostro (Sao Paulo)	+55 11 3841 6043	viccenzo.paternostro@credit-suisse.com
Australia		
Sandra McCullagh (Sydney)	+61 2 8205 4729	sandra.mccullagh@credit-suisse.com
Nik Burns (Melbourne)	+61 3 9280 1641	nik.burns@credit-suisse.com
Ben Combes (Melbourne)	+61 3 9280 1669	ben.combes@credit-suisse.com
Asia-Pacific		
David Hewitt (Singapore)	+65 6212 3064	david.hewitt.2@credit-suisse.com
Gerald Wong (Singapore)	+65 6212 3037	gerald.wong@credit-suisse.com
Horace Tse (Hong Kong)	+852 2101 7379	horace.tse@credit-suisse.com
Edwin Pang (Hong Kong)	+852 2101 6406	edwin.pang@credit-suisse.com
Yang Song (Hong Kong	+852 2101 6550	yang.y.song@credit-suisse.com
Trina Chen (Hong Kong)	+852 2101 7031	trina.chen@credit-suisse.com
Sanjay Mookim (Mumbai)	+91 22 6777 3806	sanjay.mookim@credit-suisse.com
Yuji Nishiyama (Tokyo)	+81 3 4550 7374	yuji.nishiyama@credit-suisse.com
Poom Suvarnatemee (Bangkok)	66 2 614 6210	paworamon.suvarnatemee@credit-suisse.com
A-Hyung Cho (Seoul)	+82 2 3707 3735	a-hyung.cho@credit-suisse.com
Annuar Aziz Kuala Lumpur)	+603 2723 2085	annuar.aziz@credit-suisse.com
Sidney Yeh (Taipei)	+8862 2715 6368	sidney.yeh@credit-suisse.com

Source: Credit Suisse Group.

Table of contents

Global Energy Portfolio Positioning 4
Top Picks for 2012 10
Credit Suisse Macro Assumptions 11
Energy in 2012—Transitions 12
Summary of Our Key 2012 Themes 15
12 Things That May Happen in 2012 28
Our 11 Predictions from Last Year 29
2012 Top Picks Stock Summaries 30
Oil Market: Macro Context & Outlook 38
Oil Supply: Watch Out for MENA, Saudi Policy, and Non-OPEC Performance 47
US Natural Gas in 2012 52
Focus on US Shale Gas Supply Potential 56
US Power Markets: Rethinking Demand Outlook 70
Integrated Oils—How Will Majors Spend $200bn of Excess Cash? 75
Integrated Oils—Operating Outlook 87
Global Refining in 2012—Difficult outside the US 91
Revisiting Conversion for E&P 97
US E&Ps in 2012—Focus on Self-Funded Liquid Transition Stories 99
North American Explorers Go Mainstream 115
Oilfield Services in 2012: You Should Pay Less for That Stock (but More than Today's Price!) 122
Downtime Drag Still Relevant for Offshore Drillers 130
Canadian E&P in 2012—Accelerating Asian Interest 136
MLPs in 2012, Another Strong Year 139
Canadian Infrastructure in 2012 144
Shipping in 2012 148
European E&P in 2012 152
EEMEA Oil & Gas in 2012 159
Iraq in 2012—Infrastructure and Politics 163
Asia Pac in 2012, Stay with the Upstream 171
Australian Oil and Gas in 2012 184
Latin America: YPF Gaining 187
Global Gas (ex-US) in 2012—Tight Markets Favor BG, RDS, and Total 190

Global Energy Portfolio Positioning

Before diving into the Portfolio Positioning details, a quick word on how to navigate this 200-pg report:

- **Sector Outlook:** Below, we lay out our Sector Positioning. Energy looks fairly valued versus other market sectors. We take our weighting on the Integrated Oils down to Market Weight. We favor Oilfield Services, select liquids focused E&P, Offshore Explorers, and inland US Refiners in 2012.
- **Top Picks:** The rationale for each of our Top Picks is laid out on pages 30-37 with a summary table on pg 10.
- **Energy Transitions:** On pages 12-14, we highlight some of the key Transitions that we are tracking within the Global Energy Team and that could impact share performance in 2012 and beyond.
- **Summary of Key Themes:** Over pages 15-27, we summarize the contributions of the global team that form the bulk of this report.

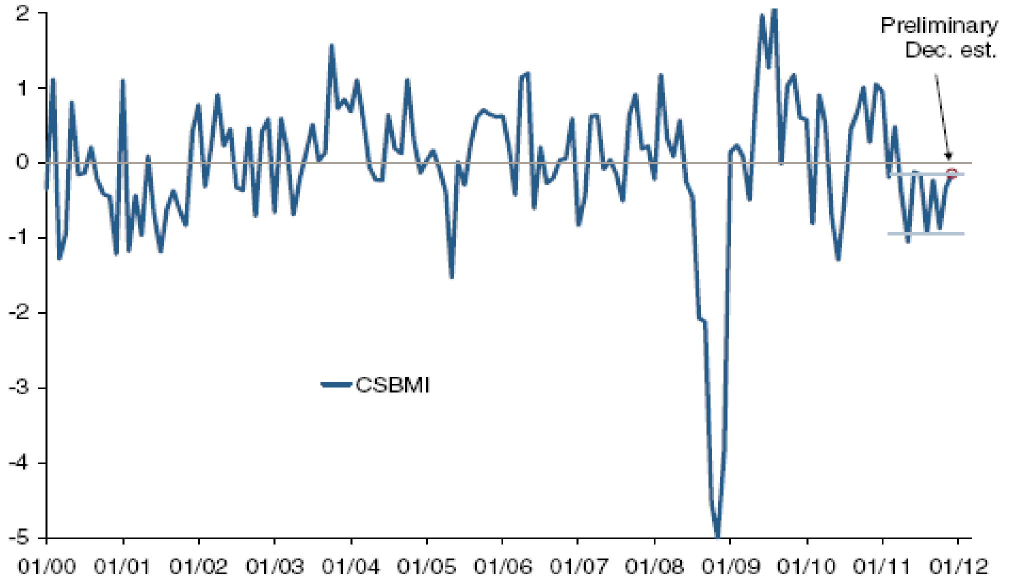
After pg 38, each of our global teams discusses themes relevant to the stocks within their region and our commodity team contributes thoughts on oil markets and US natural gas prices.

Energy looks fairly valued versus other market sectors. We take our weighting on the Integrated Oils down to Market Weight; we favor Oilfield Services, select liquids focused E&P, offshore explorers and inland US refiners in 2012

Macro Indicators Still Sluggish Entering 2012

The Credit Suisse Basic Materials Indicator (CSBMI) has been a good signal for Energy performance vs. the S&P, turning up in August 2010 and rolling over in 1Q11. Over the last six months, the CSBMI has remained in negative territory—signaling a sluggish economy, albeit with a soft upward bias from midyear lows.

Exhibit 3: **December CSBMI Improves Slightly but Remains below Zero**



Source: Company data, Credit Suisse estimates.

We continue to take comfort in the CSBMI's relative resilience vs. the much more volatile equity markets and believe it is an indicator of persistent (albeit inadequate) global growth

Good Support for Oil Prices, Tough Outlook for US Natural Gas Prices in 2012

$105/bbl Brent, $3.5/mmbtu US natural gas

Our base case envisages $100/bbl Brent in 1H12 rising to $115/bbl on average in 2013—our forecast is above the Brent futures curve average of around $100/bbl in 2013. Although near-term demand is sluggish, (and we offer a downside scenario also), we remain concerned over supply, particularly into 2013-2014.

Given the collapse in OECD demand through the Great Recession, we focus on how much of this oil demand loss is cyclical versus structural. We conclude that around 1/3 is structural, offering the possibility of an upside surprise if the OECD economies recover more strongly (not in our base case).

We see three buckets of downside volume risk on the oil supply side: North Africa and MENA instability, changed policy attitudes in Saudi Arabia, and non-OPEC underperformance. The list of producing countries that concern us either from political instability or resource issues is long—Iraq, Libya, Egypt, Algeria, Syria, Yemen, Nigeria, Sudan, Chad, Russia, Venezuela, Mexico, India, and Ecuador.

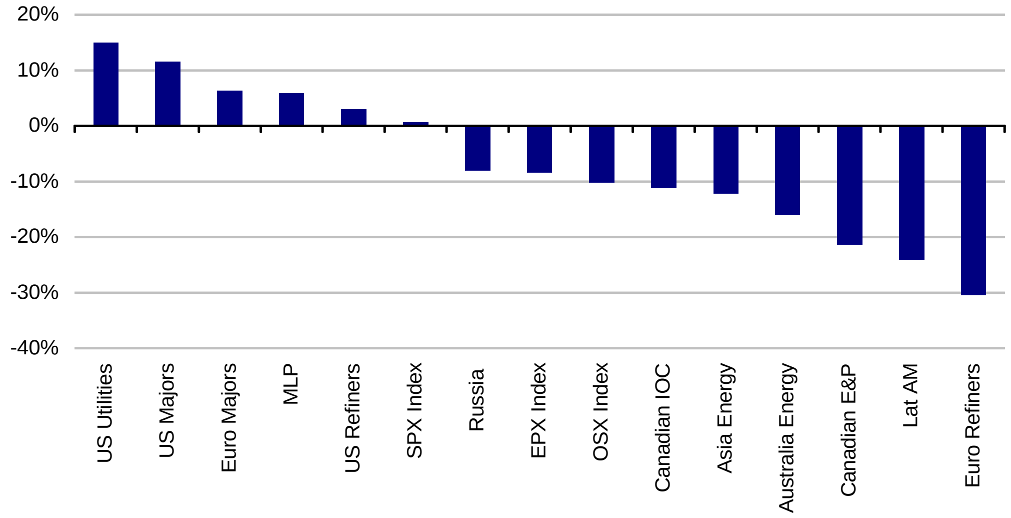
Turning to US natural gas, 2011 proved to be yet another banner year for US natural gas production. Productivity gains and technological advancements have led to a surge in production growth. Dry gas production grew +4.2 Bcf/d y-o-y, even with gas rig counts below year-ago levels. We expect growth in US natural gas production to yet again overwhelm the market in 2012, leaving end of March and October storage levels at historical highs and prices at historical lows.

Lower Integrated Oils, Raise Oilfield Services

Given underperformance outside the Majors and US refiners, we ask ourselves what went wrong in 2011 and if 2012 will be any better

Against the backdrop of European macro volatility, it seems unsurprising that Utilities, the Oil Majors, and MLP's outperformed over 2011. Given underperformance elsewhere, we ask ourselves what went wrong in 2011 and if 2012 will be any better. The quick version is that most Energy Subsectors actually delivered positive cashflow growth in 2012 and that the sector's CFPS growth outperformed the S&P. Unfortunately, this cashflow growth was overlooked as the macro environment deteriorated, leaving some value, particularly in liquids focused E&P. The notable exception with poor 2011 CFPS growth was US Oilfield Services—due to weak execution. Service demand fundamentals remain strong. We think value and better execution should lead to improved OFS share performance in 2012.

Exhibit 4: Global Energy Sector Price Performance—2011 through Dec. 24



Source: Bloomberg, Credit Suisse estimates.

US Utilities, the Majors, MLPs, and the US Refiners lead the share performance tables in 2011

If we look for rotation in 2012, then we would focus on the OSX and select liquid focused E&P names

We continue to find the US refiners undervalued and better positioned versus their global peers even in a tough demand environment

Majors: We believe there is more than just a beta trade justifying the 2011 outperformance. There has also been a significant improvement in Big Oil cashflow, a key theme of last year's *Energy in 2011: Conversion of Resources* report. However, relative outperformance leaves less upside potential at the Majors than at other large-cap Energy Names. We take our sector weighting down to Market Weight. Within the majors, RDS continues to stand out for cashflow growth and free cashflow expansion. OXY and Suncor stand out in North America. Although the European majors should have better volume growth than their US peers in 2012 (a bounce back after a disappointing 2011), offsetting risks include weak downstream and chemicals in their European operations.

Oilfield Services: Looking into 2012, we believe Oil Field Services will once again resume a leadership role for the sector in terms of cashflow growth. A derating through 2011 has left the group discounting a record high cost of capital. Some of this reflected market risk, some poor execution within the group. However, demand trends remain intact. The US, most important, is establishing itself as a less volatile market. And globally, the work that looms related to deepwater (e.g., Brazil, Gulf of Mexico, Transform Margin, Australia LNG and now Pre-salt Angola) and unconventional gas development should in most cases spur stronger, higher end, growth. If OFS companies can successfully 1) firm up contract protections in US fracturing, 2) grow production exposure, 3) strengthen logistical capabilities to derisk execution, 4) Relever balance sheets, and 5) arguably slow the pace of market share gain strategies, then better share price performance is a real possibility.

Offshore Drillers: The Offshore Drillers disappointed earnings estimates significantly in 2011 owing to downtime and still carry some EPS risk into 2012. That said, it is important to note that we expect the downtime issue to be less pronounced in 2012 than it was in 2011, when estimates were lowered by 78% for RIG, 59% for NE, and 43% for RDC. It is also worth reminding that if 2012 earnings downside risk is more modest, then it is unlikely to be the most important determinant for share performance. Instead, we submit that if dayrates continue to move higher it should raise longer term perceptions of earnings power/asset value. We remain supportive of ESV and NE on this thesis.

Select E&Ps: The beta trade and weak US natural gas prices impacted the performance of US and Canadian E&Ps in 2011 (both large and small). We believe select US E&Ps with a funded liquid transition theme should recapture a growth premium in 2012. In the offshore exploration basket listed in the US and in Europe, we include names exposed to the Angola Pre-salt, the Transform Margin, and East Africa gas.

US Refining Outperformance Should Continue: Although the US refiners outperformed some other energy groups, they lagged the improvement in balance sheet, cashflow, and investors’ appreciation of their structural advantages (i.e., access to cheap natural gas, ability to process cheap heavy crudes and discounted local crude production). We argue the US refiners should continue to be held in the global energy portfolio even as the rest of refining outside the US looks challenged. We’d use Q4 EPS weakness as an opportunity to reload.

MLPs: Unsurprisingly given the infrastructure needs of the US shales, the MLP space outperformed in 2011, particularly if dividend yields are added to capital appreciation. We remain constructive on the sector.

US Regulated Utilities: Our view for some time has been positive on the Regulated Utilities, which we expect to continue into 2012, assuming the broader equity markets and interest rates do not sharply rebound. The group’s healthy 4-5% dividend yields plus visible 3-7% EPS growth continues to support their defensive qualities, offering 7-12% annualized total return potential.

US Integrated Utilities: We expect the Integrateds to be supported by the group’s near regulated-like 3.5-4.5% dividend yield with stock-specific performance differentiation likely a result of (a) the earnings mix of merchant power vs regulated utility and (b) specific power market territory exposure to gas vs. coal and EPA policy. Catalyst wise, we think finalization of EPA rules will help clarify the power market recovery story with the trade becoming more apparent post the May 2012 PJM capacity auction (for 2015/16) and as plant closure/capex updates are announced.

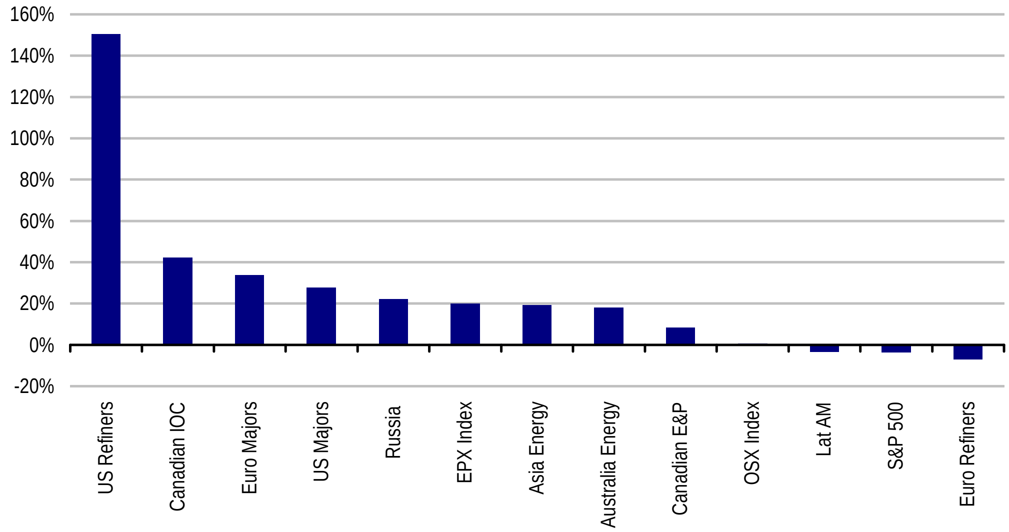
Energy, outside the US and Europe: We remain cautious on Russian Energy, citing high capex (though we like Novatek and Eurasia Drilling). We like YPF in South America owing to its significant shale potential. We stick with upstream focused names in Asia (CNOOC, COSL, Inpex). Australia will continue to struggle with high costs and some environmental headwinds—we focus on Origin, Oil Search, and Woodside.

Energy Cashflow Outperformed the S&P in 2011; OFS to Regain Leadership in 2012

The US Refiners and the Major Oils delivered the best cashflow growth in 2011

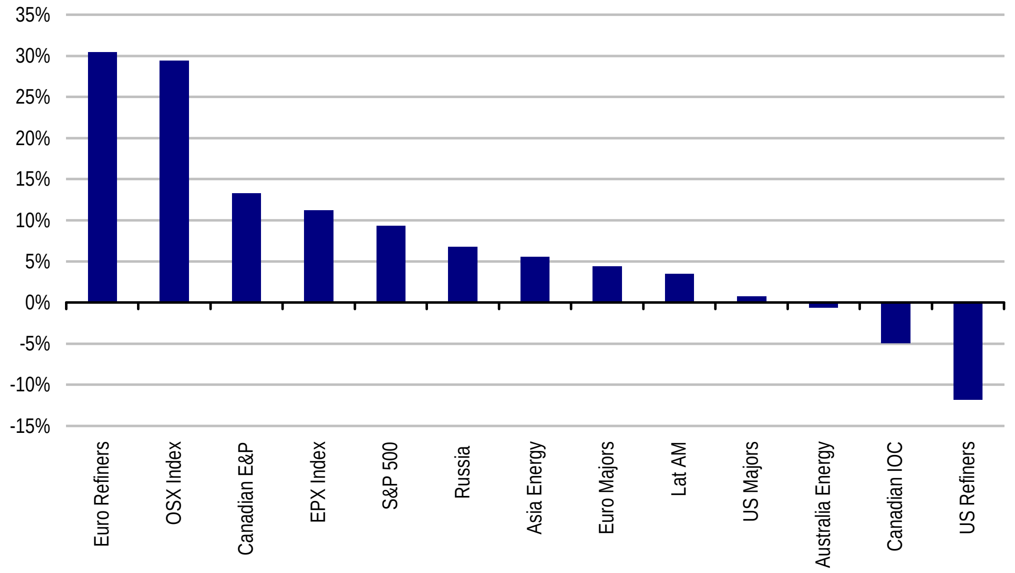
Perhaps more surprising than the relative share price moves are the changes in cashflow in 2011. Cashflow per share outpaced the S&P for nearly every energy subsector and yet shareprice performance lagged. Brent was a key driver of higher cashflows, rising 39% yoy. We don't believe Brent oil prices will rally significantly in 2012 (forecasting slightly lower oil prices in 1H12). We become more positive positive on oil prices in 2013-2014. One sector where CFPS surprisingly lagged was Oilfield Services. If, as we argue inside, the OFS sector can generate some cashflow momentum once more, it could reclaim its traditional leadership role in the sector in 2012.

Exhibit 5: Consensus CFPS Growth: 2011 vs. 2010



Source: Bloomberg, Credit Suisse estimates.

Exhibit 6: **Consensus CFPS Growth: 2012 vs. 2011**



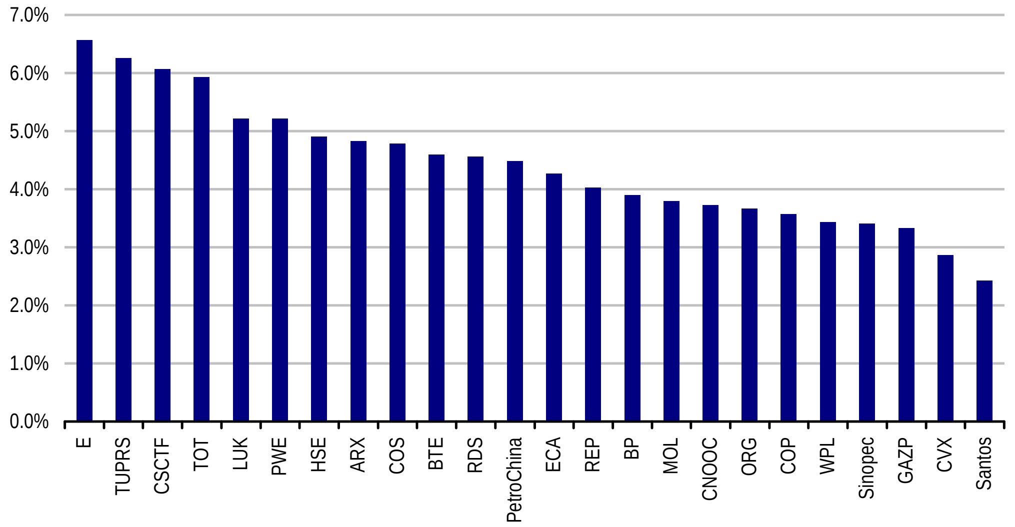
Source: Bloomberg, Credit Suisse estimates.

Those seeking CFPS growth should revisit Oilfield Services and select E&P in 2012, particularly funded liquid transition names

Dividend Appeal Is Increasing, US Refiners Could Join the High Yield Elite in 2012

With interest rates low and income at a premium, we highlight global Energy names with a decent dividend yield. More broadly, we reiterate the findings of a study by Credit Suisse HOLT® highlighting that companies in mature industries that return cash to shareholders have historically outperformed their peers. In 2012, we believe dividend payouts will increase sufficiently at the larger-cap US refiners (notably MPC, VLO and HFC) in 2012 for them to join this high-yielding elite.

Exhibit 7: **Top Dividend Payers across Global Energy above $5bn in Market Cap**



Source: Bloomberg, Credit Suisse estimates.

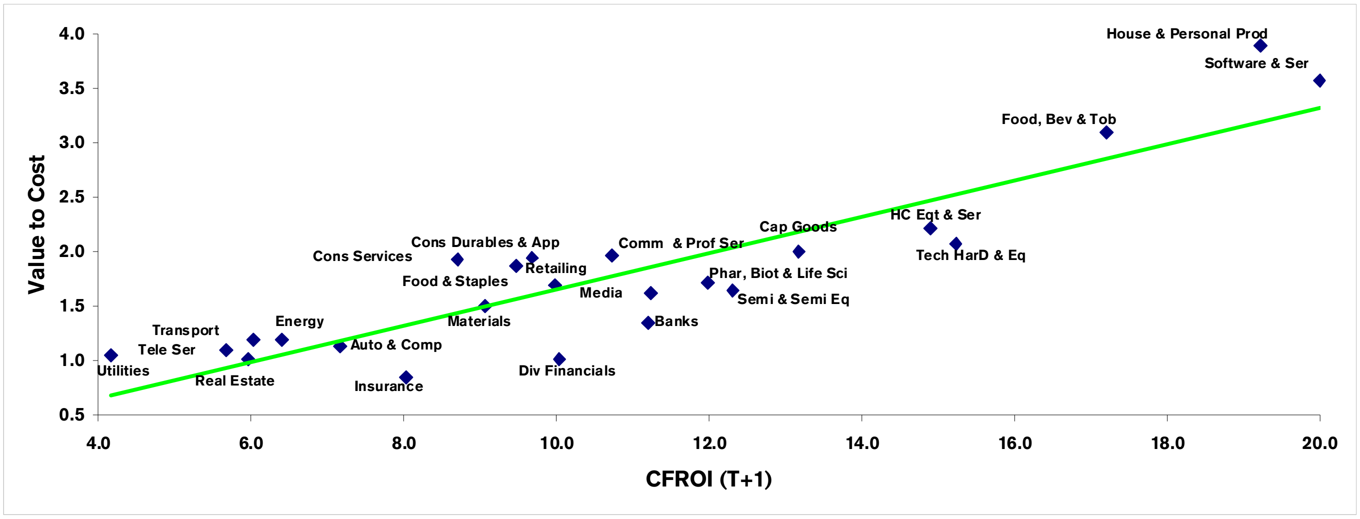
A 4.6% yield would place in the top quartile for Energy dividend yields

Strategist View—Slight Underweight on Energy

In the December 16 *2012 Outlook: Sectors, style and themes*, our strategists remain underweight of cyclicals (as they have been since March) and overweight defensives. They suggest those looking for cyclical leverage should look at Technology, Software, Semis, and Luxury Goods. Their key themes include the emerging market consumer, index-linked bond proxies, high dividend yield with high DPS growth, and investment grade structural growth. Translating their emphasis into Energy, we emphasize quality growth within Oilfield Services (assuming execution improves) and at select E&P names e.g., OXY. Using HOLT to cross-check energy's overall valuation versus competing sectors, we find Energy fairly valued versus US and European markets.

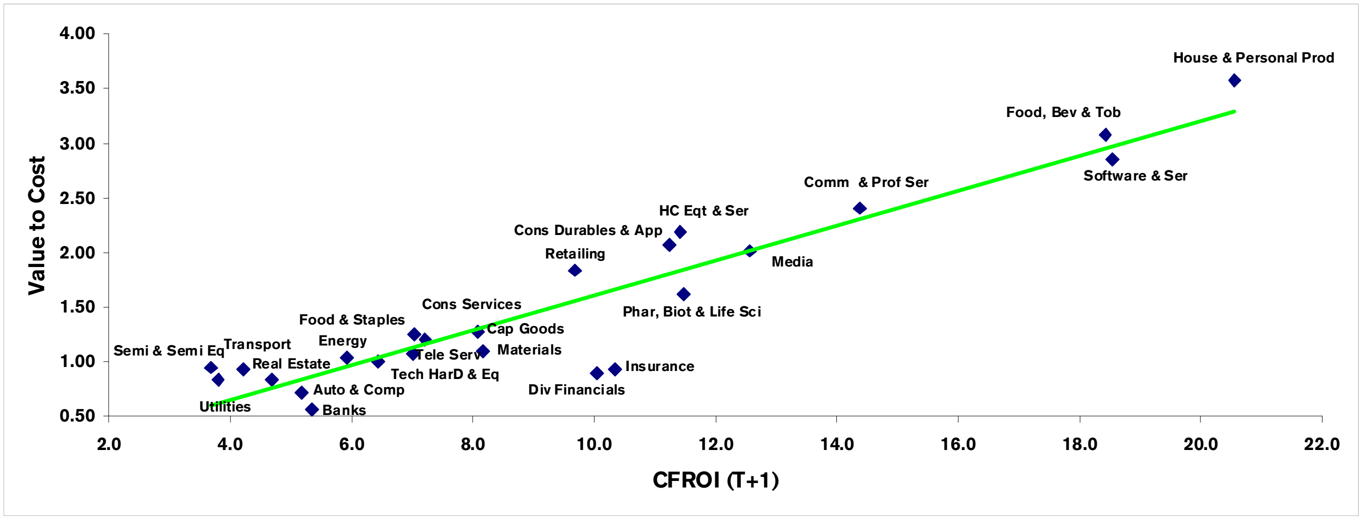
OFS set to return to leadership role in fairly valued sector relative to other US and European sectors

Exhibit 8: Energy Looks Fairly Valued Relative to Other US Industry Subsectors



Source: Credit Suisse HOLT.

Exhibit 9: Energy Looks Fairly Valued Relative to Other European Industry Subsectors



Source: Credit Suisse HOLT.

Top Picks for 2012

Exhibit 10: **Credit Suisse Traditional Energy Top Picks**

Stock	Region	Ticker	Currency	Recommendation	Current 29-Dec	Target Price	% Upside
Integrated Oils							
Repsol	Europe	REP.MC	GBP	OUTPERFORM	24	27	15%
Royal Dutch Shell	Europe	RDSa.L	GBP	OUTPERFORM	2377	2750	16%
BG Group plc	Europe	BG.L	GBP	OUTPERFORM	1371	1730	26%
Occidental Petroleum	North America	OXY	US$	OUTPERFORM	94	135	44%
Chevron Corp.	North America	CVX	US$	OUTPERFORM	107	130	21%
Refiners							
Marathon Petroleum Company	North America	MPC	US$	OUTPERFORM	33	63	89%
Western Refining Inc.	North America	WNR	US$	OUTPERFORM	13	21	55%
US E&Ps							
HESS	North America	HES	US$	OUTPERFORM	56	115	104%
Rosetta Resources	North America	ROSE	US$	OUTPERFORM	44	68	55%
Energy XXI	North America	EXXI	US$	OUTPERFORM	32	40	27%
Swift Energy	North America	SFY	US$	OUTPERFORM	30	46	51%
Cobalt	North America	CIE	US$	OUTPERFORM	16	17	9%
Kosmos Energy Ltd.	North America	KOS	US$	OUTPERFORM	12	25	104%
European E&Ps							
Premier	Europe	PMO.L	GBP	OUTPERFORM	361	490	36%
Tullow	Europe	TLW.L	GBP	OUTPERFORM	1380	1776	29%
Ophir	Europe	OPHR.L	GBP	OUTPERFORM	281	510	81%
Genel	Europe	GENL.L	GBP	OUTPERFORM	781	1093	40%
Det Norske	Europe	DETNOR.OL	NOK	OUTPERFORM	87	120	38%
Australia and Japan E&P							
Origin Energy	Asia Pacific	ORG.AX	A$	OUTPERFORM	13	17	28%
Oil Search	Asia Pacific	OSH.AX	A$	OUTPERFORM	6	7	18%
Woodside Petroleum Ltd.	Asia Pacific	WPL.AX	A$	OUTPERFORM	31	43	37%
Inpex	Asia Pacific	1605	¥	OUTPERFORM	483000	700000	45%
Canadian Oil & Gas							
Suncor	North America	SU.TO	C$	OUTPERFORM	29	50	72%
Penn West	North America	PWT.TO	C$	OUTPERFORM	20	27	34%
US Oil Field Services & Equipment							
Baker Hughes	North America	BHI	US$	OUTPERFORM	48	77	60%
Ensco Plc	North America	ESV	US$	OUTPERFORM	48	71	49%
Cameron International	North America	CAM	US$	OUTPERFORM	49	71	46%
Oil States International	North America	OIS	US$	OUTPERFORM	76	110	46%
Precision Drilling	North America	PDS	C$	OUTPERFORM	10	16	55%
GEM Oils							
Eurasia Drilling Co.	Russia	EDCLq.L	US$	OUTPERFORM	23	33	41%
NOVATEK	Russia	NVTK.RTS	US$	OUTPERFORM	12	17	41%
YPF Sociedad Anonima	South America	YPF	US$	OUTPERFORM	35	50	41%
COSL	Asia Pacific	2883.HK	HK$	OUTPERFORM	12	17	39%
Energy Infrastructure							
Boardwalk Pipeline Partners, LP	North America	BWP	US$	OUTPERFORM	28	35	27%
DCP Midstream Partners	North America	DPM	US$	OUTPERFORM	48	47	-1%
El Paso Pipeline Partners, LP	North America	EPB	US$	OUTPERFORM	35	41	18%
Targa Resources Partners, LP	North America	NGLS	US$	OUTPERFORM	37	42	12%
Capital Power Corp.	North America	CPX.TO	C$	OUTPERFORM	25	28	11%
Utilities							
Edison International	North America	EIX	US$	OUTPERFORM	42	48	16%
CMS Energy	North America	CMS	US$	OUTPERFORM	22	25	12%

Source: Bloomberg, Credit Suisse estimates.

Credit Suisse Macro Assumptions

Exhibit 11: Credit Suisse Macro Assumptions

	1Q11A	2Q11A	3Q11A	4Q11E	2010A	2011E	2012E	2013E	2014E	LT
NEW MACRO ASSUMPTIONS										
Oil & Gas Prices										
WTI ($/bbl)	93.93	102.52	89.71	95.10	79.41	95.31	99.00	113.00	117.75	84.00
Brent ($/bbl)	104.90	117.11	112.47	110.00	79.64	111.12	105.00	115.00	120.00	90.00
US Natural Gas NYMEX ($/mmbtu)	4.14	4.36	4.18	3.60	4.42	4.10	3.50	4.70	5.10	5.50
Refining Margins $/bbl										
US East Coast (PADD I) 6-3-2-1 (Brent)	7.43	8.64	9.29	8.00	7.48	8.34	6.81	6.69	6.69	6.69
US Midwest (PADD II) 3-2-1 (WTI)	16.94	29.45	32.82	19.50	9.49	24.68	15.31	11.44	12.19	15.69
US Gulf Coast (PADD III) 3-2-1 (WTI)	17.96	25.85	32.65	20.00	8.70	24.12	13.19	9.19	8.94	12.69
US Rockies (PADD IV) 3-2-1 (WTI)	24.05	32.82	42.34	32.00	18.21	32.80	20.44	17.44	18.19	21.94
US West Coast (PADD V) 5-3-1-1 (ANS)	17.17	16.42	12.98	10.25	14.33	14.21	13.74	14.24	14.24	14.24
US Gulf Coast (PADD III) 3-2-1 (LLS)	4.29	9.90	9.92	3.00	5.29	6.78	5.19	5.19	4.94	8.69
NW Europe (Rotterdam) 20-6-11-3 (Brent)	5.95	6.88	8.60	8.75	6.35	7.55	6.64	6.90	7.09	6.82
Asia-Pacific (Singapore) 6-2-3-1 (Dubai)	12.23	14.10	14.54	12.75	8.18	13.40	10.00	9.50	9.25	9.25
Crude Oil Price Discounts $/bbl										
Brent - WTI	10.97	14.60	22.76	14.90	0.23	15.81	6.00	2.00	2.25	6.00
US Heavy (WTI-Maya)	4.66	(0.75)	(8.74)	(9.00)	9.14	(3.46)	7.50	11.80	11.25	9.20
US Medium Sour (WTI-MARS)	(7.64)	(9.52)	(19.86)	(12.60)	1.42	(12.41)	(2.20)	2.35	2.60	0.80
US Sour (WTI-WTS)	4.12	2.52	0.83	0.80	2.16	2.07	1.25	2.00	2.00	2.00
LLS - WTI	13.67	15.95	22.73	16.50	3.41	17.21	8.00	4.00	4.00	4.00
LLS vs MAYA	18.33	15.20	13.99	7.50	12.55	13.76	15.50	15.80	15.25	13.20
LLS vs MARS	6.03	6.43	2.88	3.90	4.83	4.81	5.80	6.35	6.60	4.80
WTI-WCS	22.37	17.50	14.58	11.50	14.78	16.49	16.62	17.37	18.00	18.00
EU Sour (Brent-Urals)	2.96	3.08	0.38	0.50	1.39	1.73	2.44	2.63	2.63	2.38

Source: Company data, Credit Suisse estimates.

Energy in 2012—Transitions

As we head into 2012, much uncertainty remains within the global macro environment. This macro uncertainty has perhaps masked some of the important energy *Transitions* that are taking place, that we highlight throughout this report, and that could impact share performance in 2012 and beyond.

Transitions to Watch in 2012

- **We Expect the Majors to Significantly Increase Their Shale Exposure:** Right now shale resources likely represent just 10% of the Majors' resource base (concentrated thus far in natural gas). Shale is in the early stage of exploitation. We believe the Majors will use their improving free cashflow to capture larger shale exposure. $200bn excess cash after capex and dividends over 2012-2015 is a significant source of fire power to do so. In successful M&A, it normally takes two to tango. Push factors for the Independents to consolidate include low US natural gas prices and the high up-front capital costs to develop shale basins—we show inside some of the factors that can depress returns in the early stages of shale development.

- **Focus on Successful Liquids Transitions in US E&P in 2012:** We continue to view companies that have transitioned to liquids-focused shale development and are beginning to demonstrate the repeatable growth profile these assets provide to be most advantaged. Inside we update our shale play economics. Overall, the Eagleford, Mississippian, liquids rich Marcellus, core Niobrara and Wolfcamp lead the well IRR table when priced at the futures strip ($90/bbl WTI, $5/mmbtu natural gas).

- **A Transition to Better Execution in Oilfield Services Could Lead to Share Price Outperformance:** Share price underperformance and weak cashflow delivery in 2011 cause us to make a value case for OFS shares, to reiterate our confidence in demand fundamentals, and to highlight steps that management teams can take to improve the sector's embedded cost of capital. In the drilling segment, downtime decimated 2011 EPS. While downtime will remain an issue in 2012, positive demand fundamentals could provide an offset.

- **Transition to a Less Inflationary US Onshore Service Cost Environment:** We saw substantial cost inflation in the sector in 2011, primarily driven by the demand for pressure pumping equipment and the consumables required in the well completion process. With expectations of higher utilization of frac fleets and additional horsepower coming to market, our Oilfield Service team expects the pressure pumping market to become more balanced in 2H11, and therefore we do not expect similar levels of cost inflation in 2012. Despite less onshore pricing power, the derating of the OFS subsector presents an opportunity given rising global demand.

- **US Shale Transition Requires Significant Infrastructure:** The investment climate for MLPs remains supportive, in our view. Infrastructure remains short in several of the key growth basins (Bakken, Niobrara, Marcellus) and new plays continue to develop, providing the MLPs with new investment horizons (Utica, Uinta). Gathering, processing, fractionation, and logistics assets are likely to continue to perform well as drilling in the liquids-rich plays remains supported by economic returns. Furthermore, processing economics should remain healthy as we expect similar oil, NGL, and gas prices in 2012.

- **In Canada, Asia Investment Will Flow into Low Cost Natural Gas for LNG and into Heavy Oil:** Our Asia team believe Canada will likely see a decent share of Asia's M&A flows to capture gas for export and longer term heavy oil resource. While the following may or may not include an Asian partner, companies currently considering a strategic transaction of some sort include Cenovus (Borealis Region—oil sands), Connacher (Great Divide—oil sands), Husky (Ansell—tight liquids-rich gas). Other assets that could find their way into a strategic transaction over the longer term, potentially involving an Asian partner, might include ARC Resources' Attachie property in the Montney play and Lone Pine's Liard shale position in the Northwest Territories.

- **Offshore Exploration Transitions to the Mainstream:** In 2011 owing to industry success the range of stocks with meaningful exploration catalysts and a decent market capitalization has increased—TLW, APC, KOS, HESS, CIE, Det Norske, Ophir. The range of geologies to follow has also broadened owing to industry success in the Pre-salt Angola, in the Guyana basin, East Africa, and even in Norway. In the medium term, today's exploration success becomes tomorrow's offshore service demand.
- **Funding Will Become Equally Important as Resource Depth:** Gyrations in macro markets, weak US gas prices and the dominance of European Banks in international reserve based lending will keep a laser eye on funding and liquidity through 2012. We would expect an investor transition toward better funded resource upside. Our E&P basket reflects this shift.
- **Latam Investor Focus May Shift toward Argentina, from Brazil:** Within Latin America, we think the *Transition* theme will be evident in 2012, although in two opposite ways: (1) the Brazilian Energy sector is transitioning from a phase of exploration euphoria to development reality for the Pre-salt, and we think this will be illustrated by a production profile from Petrobras that will fail to provide strong oil growth until 2013-2014 at the earliest; (2) the Argentina Energy sector is transitioning to a deregulation phase, and we are also entering a new exploration period, with YPF's recent one billion bbls Vaca Muerta shale discovery being tangible evidence of the country's renewed resource potential.
- **In Australia, Managing the Transition to LNG Superpower Is Proving Expensive:** There are 8 LNG projects currently under construction simultaneously. Cost execution will remain key for this LNG superpower. Looking further out, lower cost LNG from East Africa and the US could out-compete unsanctioned Australia LNG projects.
- **US Political Transitions:** Any transition or otherwise in the White House will also impact energy policy in areas such as EPA regulation of fracking, BOEMRE regulation of offshore drilling (including the Arctic), and approvals for transborder pipelines (e.g., Keystone XL). We also revisit in this note the impact that Macondo could have on the offshore service industry's contract structure.
- **Global Political Transitions:** On the political front, there are a host of transitions in key oil suppliers which make us nervous about medium-term oil supply—Iraq, Libya, Russia, Yemen, Syria, Venezuela. Not all is bad though: countries such as Mozambique, Tanzania, and French Guiana are about to benefit from significant investment in LNG and offshore deepwater oil—Go long the New Metical?
- **In Iraq, 2012 Will Be a Pivotal Transition Year after the Completion of the US Troop Withdrawal:** The resource potential is large. In this report, we look in detail at the above-ground infrastructure and political challenges.

And Some Transitions That Look Further Off

- **Although it is tempting to call for an upturn in domestic US gas prices, our analysis suggests that markets will remain tough in 2012:** We devote a considerable part of this report to analysis of the US gas markets. On the demand side, we lower the outlook for demand from the power sector offering a detailed analysis of energy efficiency. On the supply side, we highlight drilling efficiency gains as a cap on gas prices, even when power and LNG export demand inflects higher.

- **Global LNG markets on the other hand should remain tight:** A transition to looser LNG markets could occur but not before 2016. BG, RDS and TOT will be the main beneficiaries of near-term strength in global LNG prices. As we look further out, affordability concerns in key demand centers (e.g., China) and the increased diversity of supply sources will throw the spotlight on the lowest cost producers, notable East Africa, select Floating LNG (FLNG) schemes, and North America, possibly at the expense of higher cost Australian offshore LNG projects.

- **Despite shale oil's abundance and resurgent offshore exploration success, the transition to better supplied oil markets looks like a post 2015 event:** We see broadly three buckets of downside volume risk on the supply side – instability in North Africa and the Middle East, shifting policy in Saudi Arabia and non-OPEC underperformance. Over time, i.e. beyond 2015, the significant investment flows into shale, into Brazil's offshore, into emerging exploration plays can make a difference if policy uncertainty in large producers such as Iraq, Libya, Venezuela and Russia are resolved also.

- **A refining upcycle would require 3MBD of further refinery closures:** We like the advantages of the US refiners (low cost natural gas, ability to process cheaper heavy crudes and access to low cost domestic production). However, the global refining industry faces a tough outlook with refining capacity additions and sluggish global demand keeping utilization low. We would need a further 3MBD of refinery closures or higher demand to recreate the upcycle conditions of 2005-2007.

Summary of Our Key 2012 Themes

In this section, we summarize the key 2012 themes from our Energy teams around the world that are laid out in more detail in 160 pages starting on pg 38 or so.

Oil Markets—Demand Has Weakened with the Economy but Supply Risks Remain Elevated

In essence, we expect the macro environment of 1H12 to look very much like the second half of 2011. It's only later this year that the broader economic environment begins to improve more sustainably. This will likely be another year of two halves. Transition to a more sure-footed recovery will, we hope, be the theme of 2012.

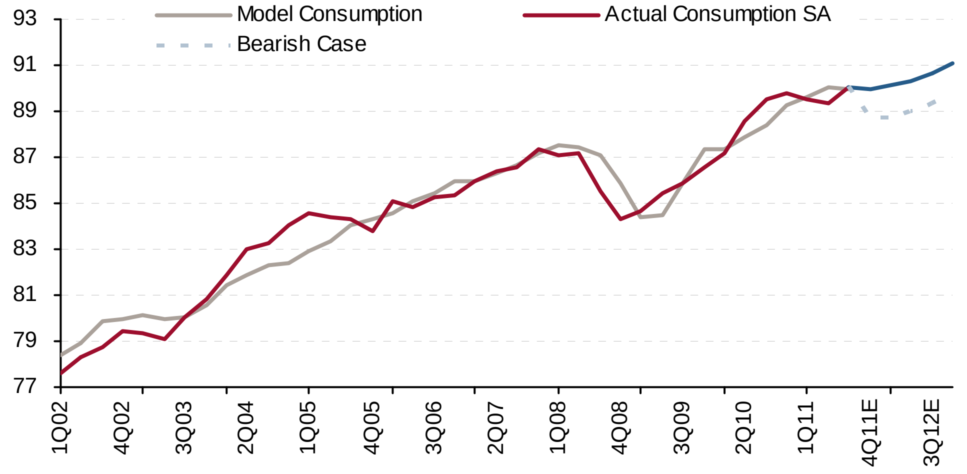
Given the macro uncertainty we outline several demand scenarios; supply risks also need to be considered

Oil Demand: Our economists have "replaced mid-2011 fears of a synchronized global recession with a more nuanced speed up scare for the US, an increasingly realized "soft landing" for China, and a more intense slowdown scare for Europe." Translating this into oil demand, our Commodity Research team use a GDP-driven regional oil demand model to determine a base outlook for global oil demand growth of +1.65 MBD in 2012. We also lay out a bear case of just +0.3MBD of oil demand growth if a European meltdown shaved 150bps off global GDP. Given the overall weakness of OECD oil demand, we focus attention on how much demand has been lost to cyclical vs. structural themes—we conclude 1/3 of the decline in OECD demand is structural. If a stronger economic recovery ever takes hold, this offers the possibility of a cyclically driven upside surprise to OECD demand (not included in our base case).

Oil Supply: We see three buckets of downside volume risk on the supply side: North Africa and MENA instability, changed policy attitudes in Saudi Arabia and non-OPEC underperformance. The list of producing countries that concern us either from political instability or resource issues is long—Iraq, Libya, Egypt, Algeria, Syria, Yemen, Nigeria, Sudan, Chad, Russia, Venezuela, Mexico, India, Ecuador.

Oil Prices: Our base case envisages $100/bbl Brent in 1H12 rising to $115/bbl average in 2013 (the futures curve is $100/bbl in 2013). In a European meltdown, Brent oil prices could fall to a quarterly average of $70/bbl. As in 2009, we would expect any period of low prices to be relatively brief, given the underlying cost dynamics to replace a declining production base—a *Reboot* would return prices back toward triple digits in 2013-2014.

Exhibit 12: **Global Oil Demand Scenarios (MB/D)**



Source: Credit Suisse Commodity Research.

US Gas Price—Best Hope Is That 2012 Is a Transition Year

2011 proved to be yet another banner year for US natural gas production. Productivity gains and technological advancements have lead to a surge in production growth. Dry gas production has averaged an impressive 61.3 Bcf/d in 2011 according to most recent pipeline flows, good for a +4.2 Bcf/d y-o-y gain, yet gas rig counts have remained under year-ago levels. We expect growth in US natural gas production to yet again overwhelm the market in 2012, leaving end of March and October storage levels at historical highs but prices at historical lows.

Rising production and a weak economy suggest continued price weakness in 2012

However, we are now characterizing 2013 as a transition year when balances and storage levels begin to move back into normal ranges, followed by improvements in natural gas prices. Further along the curve, we hold our favorable view for US gas demand through a number of policy initiatives as well as prospects for LNG exports from the US and Canada. That said, we have lowered our prior demand forecasts reflecting work from our US utility team on energy efficiency. A key risk to this gas price renaissance (albeit from low levels) is the improving productivity of shales.

We are positive on medium-term demand, but have shaved our prior forecasts reflecting work from our US utility team on energy efficiency

Exhibit 13: **Credit Suisse Natural Gas Supply-Demand Model**

(Bcfd)	2010	2011E	2012E	2013E	2014E	LT (Real)
Dry Gas Production	**59.1**	**62.8**	**63.9**	**62.3**	**64.0**	
Y-o-Y	2.7	3.7	1.1	(1.6)	1.7	
Canadian Imports (Net)	**7.0**	**6.0**	**5.7**	**6.3**	**6.0**	
Y-o-Y	(0.1)	(0.9)	(0.3)	0.5	(0.3)	
Mexican Exports (Net)	**(0.8)**	**(1.3)**	**(1.4)**	**(1.6)**	**(1.8)**	
Y-o-Y	0.0	(0.5)	(0.1)	(0.2)	(0.2)	
LNG Imports (Net)	**1.2**	**0.7**	**0.7**	**0.6**	**0.5**	
Y-o-Y	(0.1)	(0.4)	(0.1)	(0.1)	(0.1)	
Total Supply	**66.4**	**68.2**	**68.9**	**67.6**	**68.8**	
Y-o-Y	2.6	1.8	0.7	-1.3	1.2	
Industrial	**18.1**	**18.4**	**18.7**	**19.1**	**19.2**	
Y-o-Y	1.2	0.4	0.2	0.4	0.1	
Power	**20.2**	**20.7**	**21.5**	**22.3**	**23.0**	
Y-o-Y	1.4	0.5	0.8	0.8	0.8	
Y-o-Y Growth From Coal ret.			-	0.3	0.5	
Res/Comm	**22.4**	**22.1**	**22.5**	**22.5**	**22.3**	
Y-o-Y	0.7	(0.3)	0.4	0.0	(0.2)	
Other	**5.4**	**5.6**	**5.7**	**5.9**	**5.9**	
Y-o-Y	0.3	0.2	0.2	0.2	(0.0)	
Total Demand	**66.0**	**66.8**	**68.4**	**69.8**	**70.5**	
Y-o-Y	3.5	0.8	1.6	1.3	0.7	
Price Forecast ($/Mmbtu)	**$4.38**	**$ 4.07**	**$ 3.50**	**$ 4.70**	**$ 5.10**	**$ 5.50**
Previous Forecast ($/Mmbtu)		**$ 4.20**	**$ 4.40**	**$ 4.90**	**$ 5.50**	**$ 5.50**

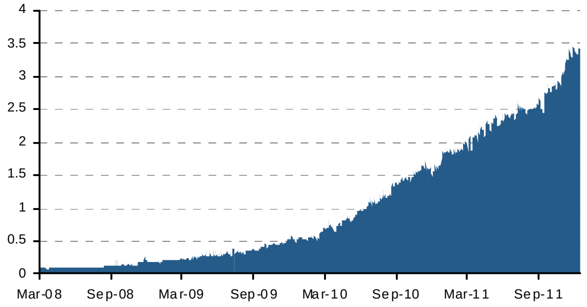
Source: EIA, Credit Suisse estimates.

Longer-Term US Shale Gas Potential—Beware Efficiency Gains

Efficiency gains are evident in the US gas shale drilling; the Marcellus (and Utica) could emerge as key caps on gas price upside once infrastructure is in place

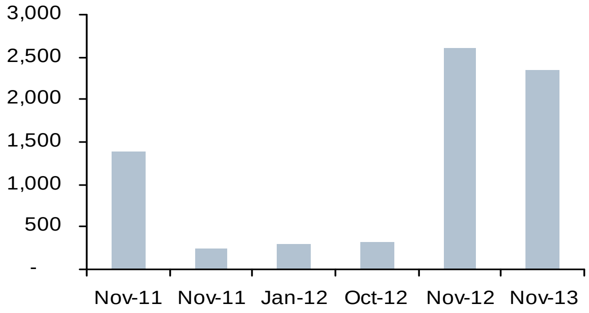
The significant increase in natural gas supply has been driven by the remarkable increase in shale development, with US natural gas production from shales poised to exceed 20 bcf/d by early 2012. It took the industry approximately 18 years to reach 5 bcf/d in production, but advances in horizontal drilling and completion technology have sharply compressed the cycle time. In fact, the industry is on track to grow natural gas supplies from shales by 10 bcf/d in less than 2 years. Despite reductions in natural gas drilling activity, there have been sharp improvements in productivity that have more than offset the impact from a lower gas rigcount. These efficiency improvements include the increased use of high-spec land rigs that are better suited to drill horizontal wells much more efficiently than conventional rigs, increases in lateral lengths that have boosted production rates per well, advances in stimulation technology such as cluster fracs, as well as microseismic data to optimize the placement of laterals and widespread use of PDC drill bits. While there have been improvements in all of these key plays, the key near-term challenge for the supply picture is the Marcellus Shale play, which is in the early stages in development. Unlike the other key natural gas plays, efficiency gains associated with the Marcellus have been modest despite significant increases in EURs. The Marcellus (and Utica) could emerge as key caps on gas price upside once infrastructure is in place.

Exhibit 14: Daily Marcellus Gas Production



Source: Energy Velocity, Credit Suisse.

Exhibit 15: Marcellus Pipeline Expansions



Source: Company data, Credit Suisse estimates.

US Power Sector's Demand for Gas Is Lower Than We Previously Forecast

Lowering natural gas growth from power by 2bcfd in 2015

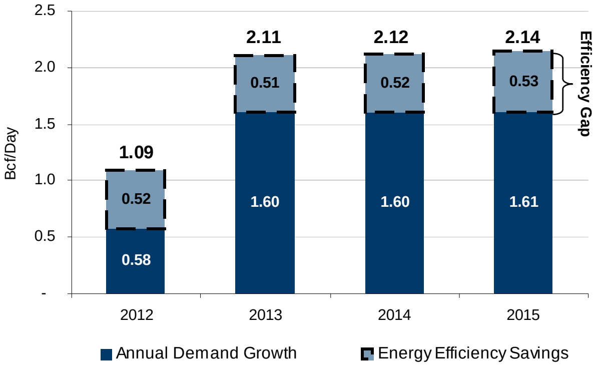
We are growing more concerned that the medium- to longer-term US power demand outlook needs to be reconsidered as the impact of state efficiency programs and advances in device efficiency slows the trajectory of growth. We appreciate demand growth forecasts tend to fall into the school of art over science but are seeing issues that could help account for the disappointing usage trends seen at utilities this year with knock-on effects into the future.

We see potential demand growth reductions of 0.6-0.8% per year relative to a base normalized growth assumption of 1.5% per annum, or a ~50% drop in the rate of electricity demand growth. We come to these reductions two ways:

- State specific energy efficiency programs and enforcement of light bulb rules for Residential customers in states without specific standards; and
- Buildup of efficiency gains focused on Residential customers through the light bulb standards, improvements in HVAC performance, and general appliance efficiency gains.

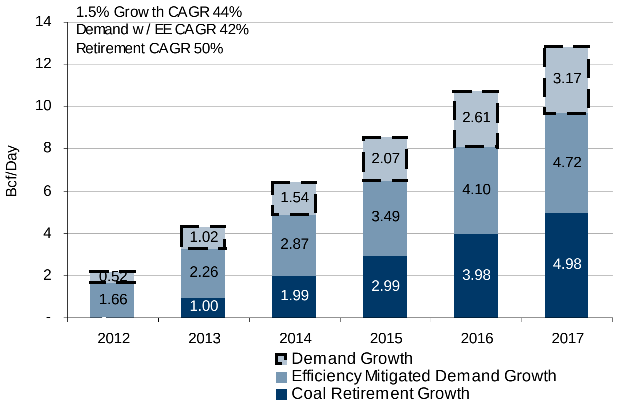
We stress that natural gas demand will continue to grow with more power generation use but that the rate of growth could look slower than what is underpinning a more bullish natural gas outlook.

Exhibit 16: Annual Efficiency Impact on Gas Demand



Source: Company data, Credit Suisse estimates.

Exhibit 17: Cumulative Impact on Gas Demand



Source: Company data, Credit Suisse estimates.

Integrated Oils—How Will the Majors Spend $200bn of Excess Cash?

Last year in Energy in 2011, we made much of the fact that Big Oil's cashflow outlook was being underestimated. This is partly a function of their greater leverage to Brent oil prices—the majors generally have a higher share of oil production and oil-priced linked international gas production in the mix, particularly relative to US E&P's who are more exposed to declining US natural gas prices. It is also a function of rising underlying cashflow per barrel margins on their new projects. Although we and many investors have historically criticized the majors for declining free cashflow and limited top-line growth, the majors have in fact invested heavily to increase their sensitivity to higher oil prices through the choice of fiscal regime and invested to defer their maintenance capital requirements by bringing on longer lived production e.g., LNG and heavy oil.

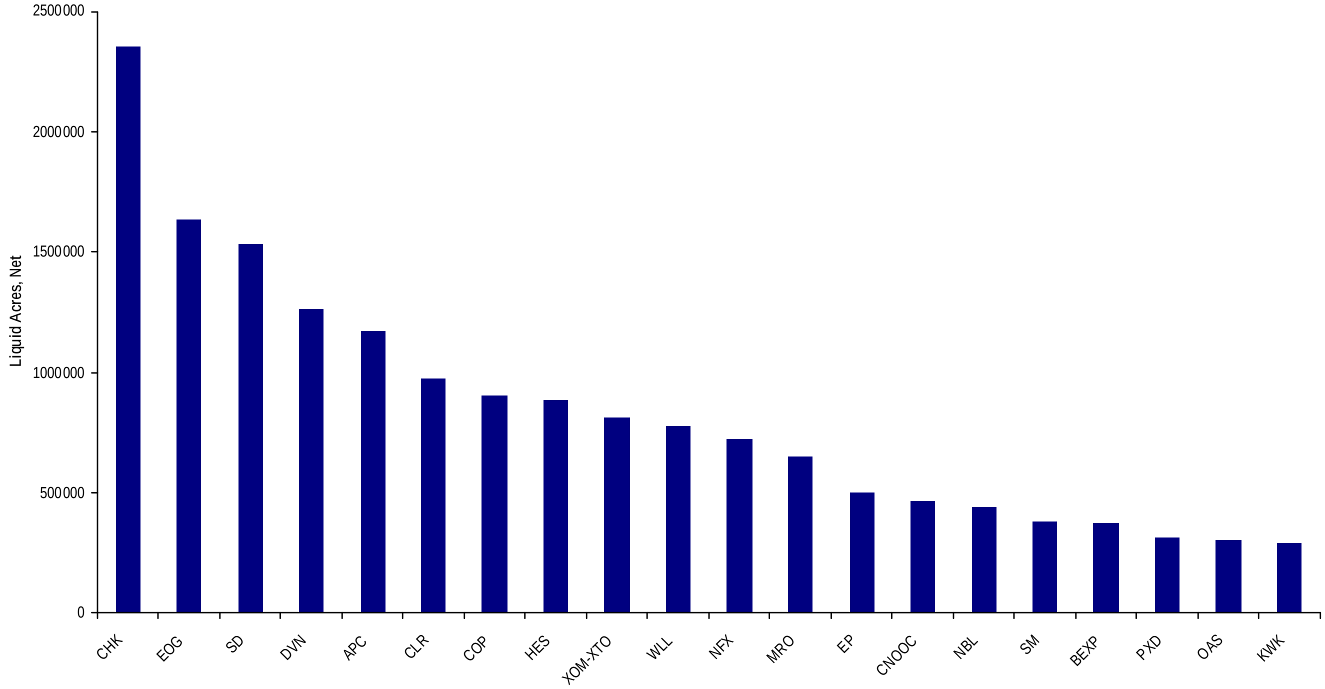
Free cashflow has surprised; our attention focuses on where it will be deployed

Without the following wind of higher oil prices in 1H12 and after outperforming, we take down our weighting to Market Weight

As free cashflow rises, in *Energy in 2012: Transitions* will focus on where the majors will deploy their cashflow in 2012 and beyond. Indeed we calculate that the majors should have $200bn of free cashflow over 2012-2015 after paying dividends and capex at their discretion and without any releveraging of their underutilized balance sheets.

We believe much of the focus will be on liquids acreage in North America, though emerging offshore exploration hotspots could also attract M&A flows. We include analysis to suggest that in their early days, shales can be more capital intensive than the market suspects (due to well results variability, HBP drilling inefficiency, infrastructure spend). Low gas prices and up-front capital costs could drive some Independents into the arms of the Majors.

Exhibit 18: **Large North America Liquid Shale Acreage Holders**



Source: Company data, Credit Suisse estimates.

Aside from deployment of cashflow, we focus on the operating outlook for the majors. RDS wins overall, benefiting from production ramps AND tight LNG markets. While the European Majors should deliver better production growth than US peers in 2012 (a bounce back from a disappointing 2011), we are concerned about a weak European downstream and chemical environment. Without the following wind of higher oil prices in 1H12 and after outperforming, we take down our weighting to Market Weight.

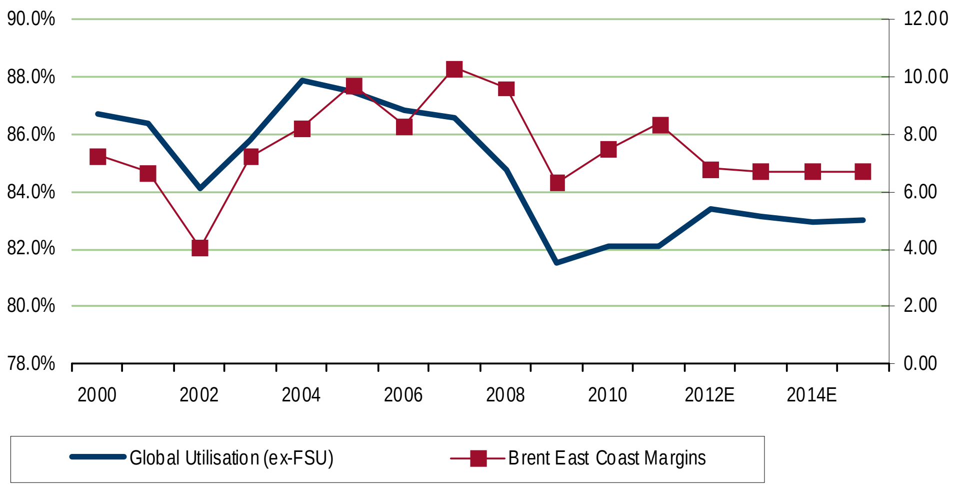
RDS to deliver the best operational momentum in 2012

Global Refining in 2012—Difficult outside the US

2012 is likely to remain as difficult for non-advantaged refiners as 2011. Although Libya should bring more light sweet crude back into the market, end-user demand in the OECD remains weak and we cannot rule out other light sweet crude supply disruptions (e.g., Nigeria). In the oil commodity section, we lay out various scenarios for global demand. Although we remain of the view that oil demand will remain positive, driven by the non-OECD, we don't believe global utilization will rise sufficiently to stress refining markets without further closure. Complex US refiners with access to low cost crude can still make decent money even within this outlook, but for the remainder, survival is the most important decision-making driver.

Up to 3MBD more closures (or higher demand) required to recreate “Golden Age” upcycle; we remain Overweight the US refiners

Exhibit 19: **Global Utilization—More Closures Required**



Source: Company data, Credit Suisse estimates.

US E&Ps—Focus on Self-Funded Liquid Transitions

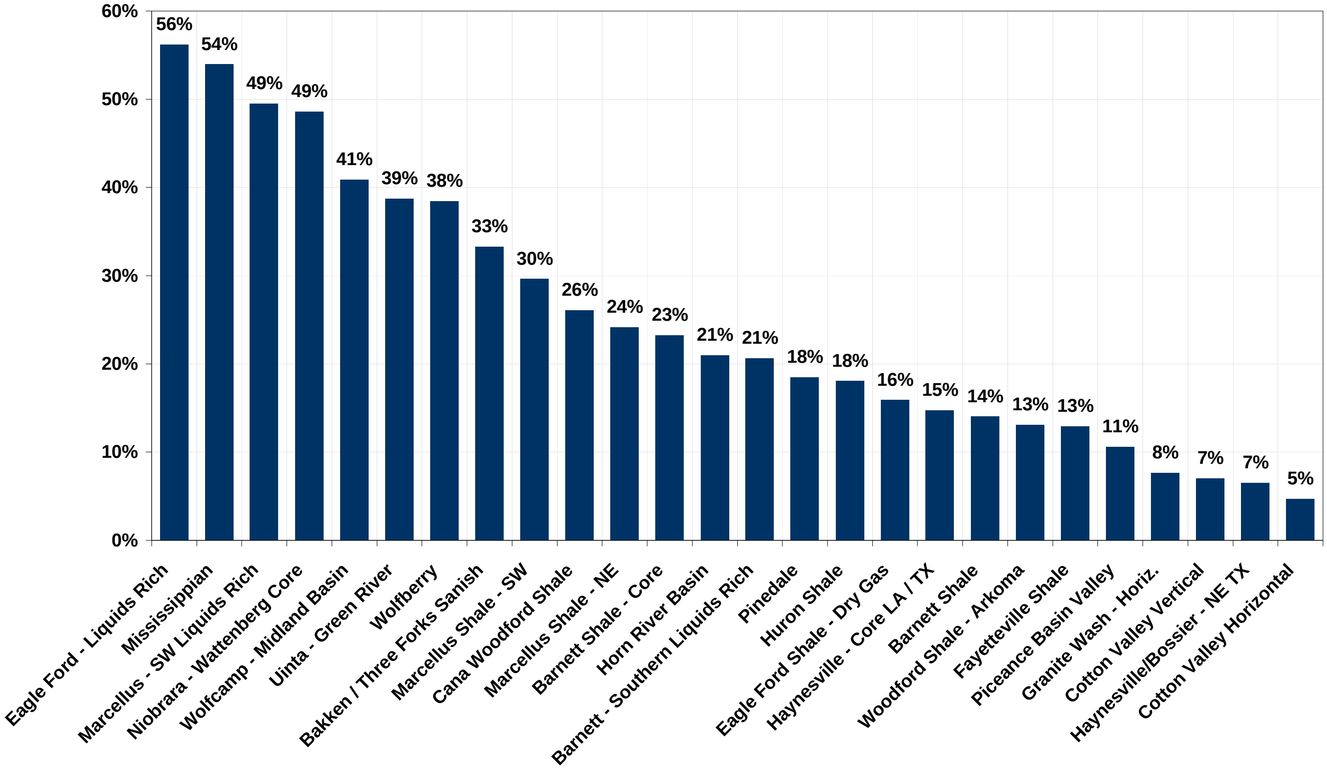
For US E&P in 2012 we continue to view companies that have *Transitioned* to liquids-focused shale development and are beginning to demonstrate the repeatable growth profile these assets provide to be most advantaged. In 2011, we saw results improve in leading shale plays, such as the Eagle Ford and Marcellus, and continue to see operators step out to new areas in attempt to replicate shale success, such as the Utica and new targets in the Permian. In the SMID-cap group we prefer the stocks of liquids-focused E&Ps with deep, high-return project inventories that are focused on delivering cash flow (*per share*) growth and are able to fund that growth in an uncertain macroeconomic environment. Our top picks in the SMID-cap E&P group for 2011 are ROSE, EXXI and SFY.

Updated US Shale Play Economics

Focus on the Eagle Ford, Mississippian, core Niobrara, Marcellus liquids Rich, and emerging Permian in 2012

Liquids-rich basins continue to provide significantly higher rates of return driven by higher oil prices and the continued weak natural gas price environment. On average, the liquids-rich plays (*Eagle Ford*, *Mississippian, core Niobrara*, *Marcellus SW Liquids-Rich, emerging Permian, Bakken*) provide rates of return that are more than 20 percentage points higher than dry gas plays at the current futures strip. Notably, we have added a number of new liquids plays to our basin return analysis, including the horizontal Mississippian, Wolfberry, and Wolfcamp plays in the Permian Basin, the Niobrara in the DJ Basin and the vertical Green River play in the Uinta Basin.

Exhibit 20: US Basin Internal Rates of Return (IRRs)—*Credit Suisse Price Forecast*



Year:	1	2	3	4	5	6	7	8+
WTI Oil:	$99.00	$113.00	$117.50	$84.00	$84.00	$84.00	$84.00	$90.33
NYMEX Gas:	$3.50	$4.70	$5.10	$5.50	$5.50	$5.50	$5.50	$4.85

Source: Company data, Credit Suisse estimates.

We Expect US Onshore Cost Inflation to Moderate

We saw substantial cost inflation in the sector in 2011, primarily driven by the demand for pressure pumping equipment and the consumables required in the well completion process. With expectations of higher utilization of frac fleets and additional horsepower coming to market, our OFS team expects the pressure pumping market to become more balanced in 2H11, and therefore we do not expect similar levels of cost inflation in 2012. In 2011, it was evident that the Williston Bakken and Eagle Ford experienced higher-cost pressure than other plays, and operators are taking steps to increase efficiencies to offset cost increases, including pad drilling and testing new completion technologies

Funding Risk amid Uncertain Macro Environment

With a focus also on balance sheet strength, we look at net debt-to-cash flow multiples for the group in 2012 and 2013 with commodity prices at the futures strip *($94.09/Bbl WTI and $3.37/MMBtu gas in 2012 and $91.81/Bbl WTI and $3.99/MMBtu in 2013*). At the strip in 2013, 76% of the companies in this analysis maintain ratios below 4.0x, which is significant in that typical bank credit facility covenants typically require total leverage (*net debt-to-EBITDA*) to remain below 4.0x. GPOR and EXXI screen the best at -0.5x and 0.5x, respectively, while GMXR at 51.4x, FST at 5.1x and PVA at 5.0x are the most stretched in 2013.

North American Explorers Go Mainstream

International exploration has been one of our key fall 2011 themes and will continue into 2012. Although historically most investors would associate offshore exploration with the European Independent E&P sector, we believe North American offshore explorers have become an compelling investment theme. We highlight CIE, KOS, HES, APC, NBL, EXXI, and NIKO as companies drilling material wells over the next 12 months. Key areas to watch for the North American Explorers include Pre-salt Angola, Ghana, West Africa Transform Margin, East Africa gas, South China Sea, Gulf of Mexico, Deep Shelf Gas, West Med Gas, and Indonesia.

Oilfield Services in 2012: You Should Pay Less for That Stock (but More than Today's Price!)

If they execute, Oilfield Services can regain sector leadership in 2012

Share price underperformance and weak cashflow delivery in 2011 cause us to make a value case for Oilfield Service shares. We reiterate our confidence in demand fundamentals (offshore they are improving) and highlight steps managements can take to improve the sector's embedded cost of capital.

Embedded cost of capital has nearly doubled since 2000

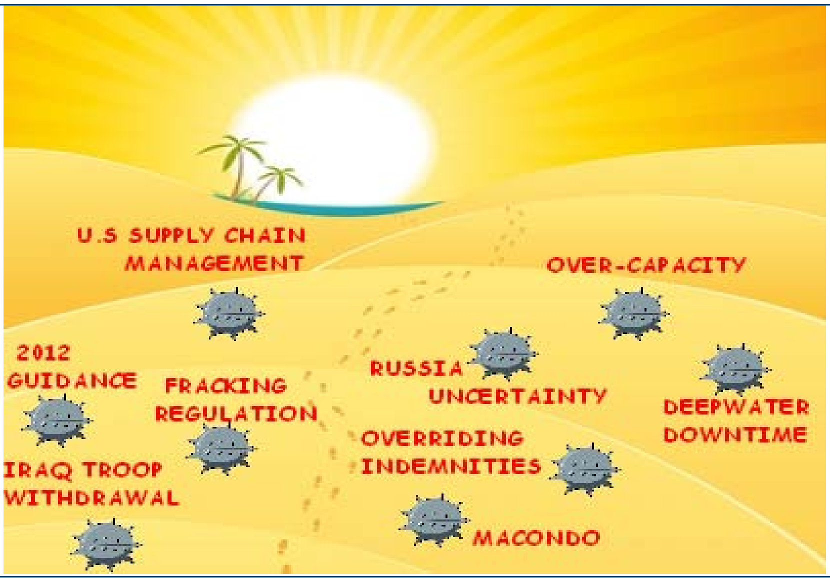
Value Case: We think it makes sense that OFS stocks should trade at lower multiples than they have in prior cycles. This is primarily due to equity markets and risk premiums, which have raised their cost of capital, but we acknowledge operational risks for the sector as well. **However, we believe shares should appreciate from current levels, because the current focus on margins and other operating challenges ignores the longer term potential for revenue, earnings, and cash flow growth over the coming cycle.** Further, we believe there are steps the companies are taking and can take to minimize volatility and unlock shareholder value and in turn lower their capital costs. OFS has two, in part related, challenges currently: 1) there is apparent risk in operations that can impact 2012 earnings (and plausibly beyond); and 2) the cost of capital for the sector (WACC) has nearly doubled since 2000. This latter challenge is a function of sector volatility (higher Beta), but also of rising equity risk premium. We think the risks are concentrated on the execution (and not the demand) side.

MENA demand risks remain; however, we believe the US is becoming a less volatile market and there is a lot of work to be done in deepwater/global gas.

OFS Demand Outlook Remains Robust: There are indeed risks to the demand side, including 1) the Middle East/North Africa region, in our view, given political uncertainty and 2) the "slow bleed" of hydraulic fracturing regulatory risk that could impact demand in the US, Australia and elsewhere. However, we contend that it is the demand side that argues for multiple appreciation in shares. The US most important is establishing itself as a less volatile market. And globally, the work that looms related to deepwater (thanks to existing discoveries and recent exploration success) and unconventional gas development should in most cases spur stronger, higher-end growth.

Better Execution Required: In our view, the most important current operating challenges are concentrated on the cost side; we address some of these in the "OFS Minefield" section as well as for the offshore drillers section. We sense that companies can help address the concerns that are contributing to higher cost of capital. These steps can include: 1) firming up contract protections in US fracturing, 2) growing production exposure (e.g. artificial lift, chemical injection, fluid analysis, and field management), 3) strengthening logistical capabilities to de-risk execution, 4) relever balance sheets, and 5) arguably slow the pace of market share strategies.

Exhibit 21: The OFS Minefield on the Path to Growth



Source: Dreamstime LLC., Clker, Credit Suisse.

If management teams can avoid some of the OFS execution pitfalls, there is more than usual upside potential in the group

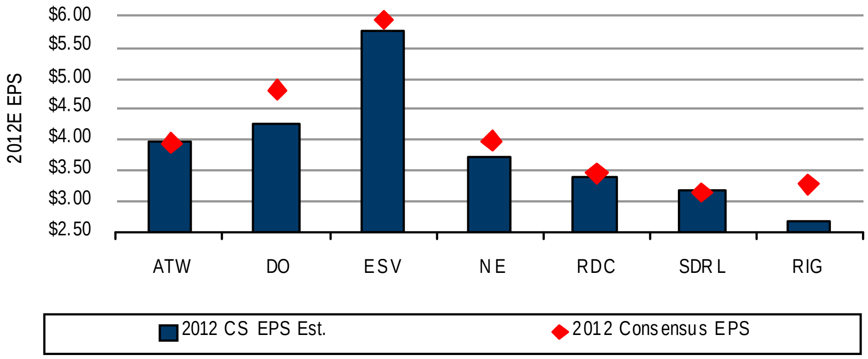
Downtime Drag Still Relevant for Offshore Drillers

Earnings disappointed significantly in 2011; downtime is still a drag but we think share price underperformance and robust demand fundamentals present an opportunity; we like ESV and NE

The Offshore Drillers disappointed earnings estimates significantly in 2012. The segment appears to have solid demand, but still carries risk to 2012 earnings, as the market has not fully adjusted for greater than expected rig downtime. That said, it is important to note that we expect the downtime issue to be less pronounced in 2012 than it was in 2011, when estimates were lowered by 78% for RIG, 59% for NE, and 43% for RDC. The companies are offering greater visibility on expected downtime (with RIG being the most important case in point), and we believe the Blowout Preventer (BoP) recertification process that followed the Macondo disaster of 2010 has been largely completed.

It is also worth reminding that if 2012 earnings downside risk is more modest, then it is unlikely to be the most important determinant for share performance. Instead, we submit that if dayrates continue to move higher, it should raise longer-term perceptions of earnings power/asset value. We remain supportive of ESV and NE on this thesis.

Exhibit 22: 2012E EPS: Credit Suisse vs. Consensus



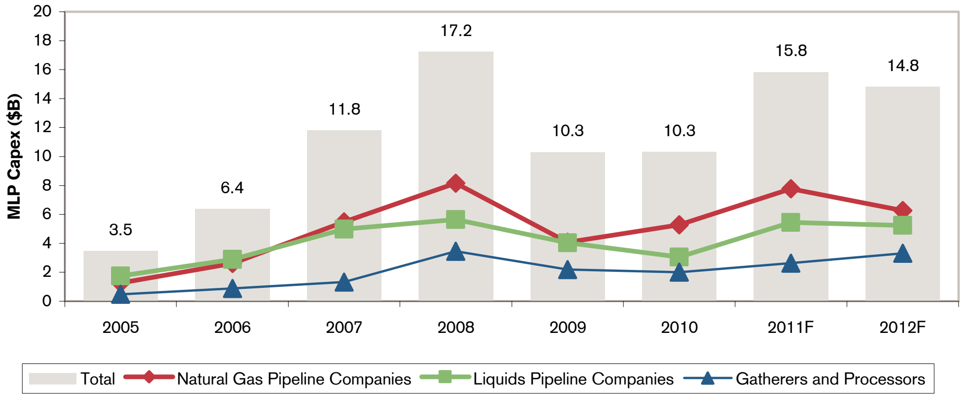
Source: Company data, Credit Suisse estimates.

Investment Climate for MLPs Remains Supportive

MLP's benefiting from the high capital required to connect shales to market and strong NGL economics

The investment climate for MLPs remains supportive, in our view. Infrastructure remains short in several of the key growth basins (Bakken, Niobrara, Marcellus) and new plays continue to develop providing the MLPs with new investment horizons (Utica, Uinta). Gathering, processing, fractionation, and logistics assets are likely to continue to perform well as drilling in the liquids-rich plays remains supported by economic returns. Furthermore, processing economics should remain healthy as we expect similar oil, NGL and gas prices in 2012. Finally, we do expect project competition to heat up in 2012. Growth basins and services are likely to draw additional competition, thus lowering project returns (albeit at still healthy levels).

Exhibit 23: MLP Capex (2005-2012F)



Source: Factset, Company data, Credit Suisse estimates.

Gas JVs Strengthen the East-West Connection in Canada

Asian investment in Canada's oil and gas sector has accelerated

Asian investment in Canada's oil and gas sector has accelerated over the past three years through a combination of joint ventures, asset purchases, and opportunistic M&A. While individual deal size has remained relatively small (i.e., below the C$5 billion threshold), taken together, recent Asia-Canada transactions now add up to over C$20 billion. Investment by Asian entities into Canada has also broadened to include the likes of PTTEP and PETRONAS, and increasing emphasis is being placed on shale gas joint ventures with a view to future LNG exports off the West Coast. We believe the East-West connection between Asia and Canada is set to expand further, as both markets seek to diversify their resource exposure.

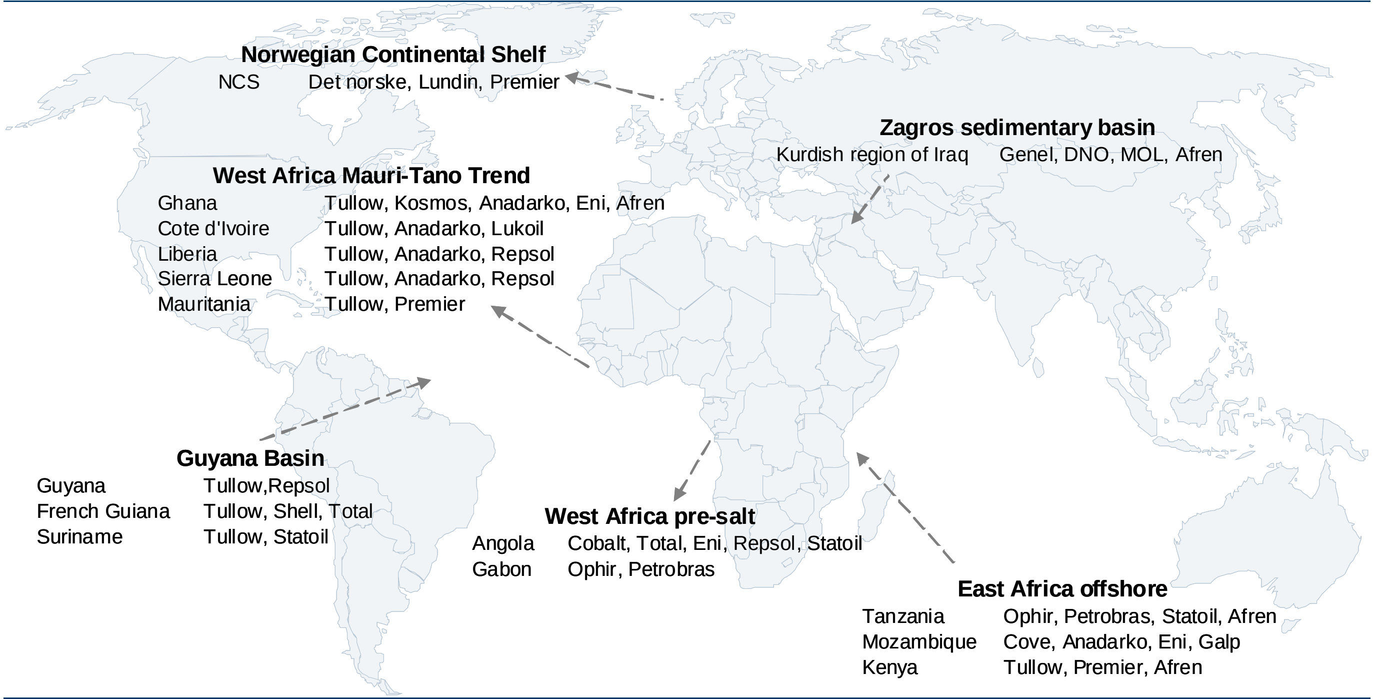
European E&P in 2012—Ophir, Det Norske, Tullow

The larger European E&Ps offer an exciting pipeline of exploration prospects that appear well funded in 2012

Key focus areas include West Africa, Guyana Basin, East Africa gas, and Iraq

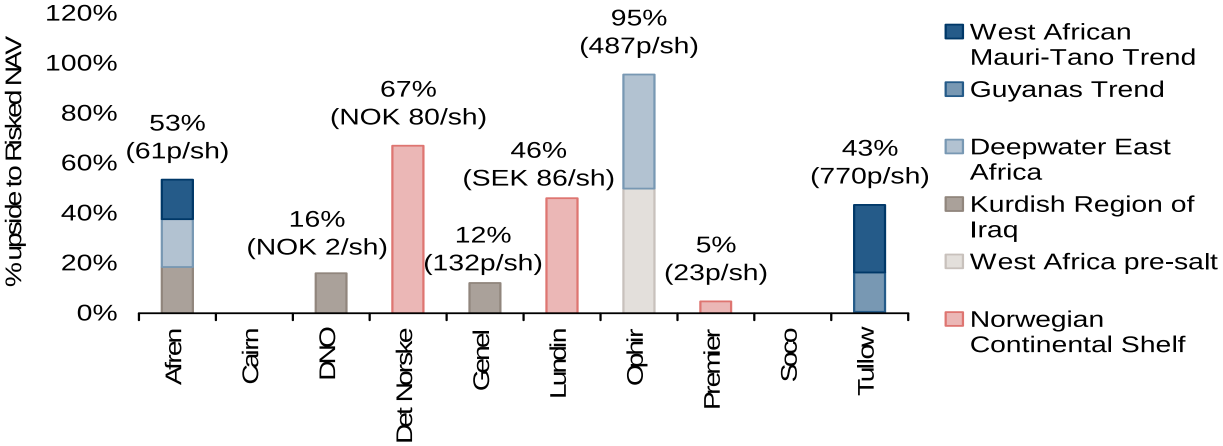
In our European E&P coverage, we continue to favor attractive growth stocks with fundamental value and cashflow support and/or coupled with exploration catalysts in the right geological "postcodes." Funding ability is also likely to play a more pivotal role, especially if the current debt crisis were to deteriorate further. This thematic is also likely to continue to support M&A activity in the sector, as weaker players are acquired, either for cheap reserves or to facilitate project development. We continue to focus on the West African Mauri-Tano Trend, where Tullow is looking to extend the Jubilee play. The Guyanas Trend on the South American side of the Equatorial Atlantic transform margin looks attractive after the Zaedyus discovery in French Guiana derisked a huge new opportunity set. Deepwater East Africa will remain in focus as BG/Ophir will drill 5-6 wells in Tanzania by 2012-end, while Eni/Galp and Cove/APC continue drilling in Mozambique. Several near-term wells are planned in the Kurdish region of Iraq targeting the highly prolific Zagros sedimentary basin. We also highlight the Norwegian Continental Shelf as a reemerging exploration hotspot (Lundin/Det norske) after the recent Avaldsnes/Aldous discoveries. Although still early days for Pre-salt West Africa, this thematic could pick up momentum after Cobalt's initial success in Angola. We are not bearish on Greenland, but the inconclusive drilling results by Cairn do not provide much confidence going into 2012.

Exhibit 24: **European E&Ps—Key Exploration Focus Areas in 2012**


Norwegian Continental Shelf
NCS Det norske, Lundin, Premier
Zagros sedimentary basin
Kurdish region of Iraq Genel, DNO, MOL, Afren
West Africa Mauri-Tano Trend
Ghana Tullow, Kosmos, Anadarko, Eni, Afren
Cote d'Ivoire Tullow, Anadarko, Lukoil
Liberia Tullow, Anadarko, Repsol
Sierra Leone Tullow, Anadarko, Repsol
Mauritania Tullow, Premier
Guyana Basin
Guyana Tullow,Repsol
French Guiana Tullow, Shell, Total
Suriname Tullow, Statoil
West Africa pre-salt
Angola Cobalt, Total, Eni, Repsol, Statoil
Gabon Ophir, Petrobras
East Africa offshore
Tanzania Ophir, Petrobras, Statoil, Afren
Mozambique Cove, Anadarko, Eni, Galp
Kenya Tullow, Premier, Afren

Source: Credit Suisse Research.

Exhibit 25: **2012 Drilling in Key Focus Areas—Blue Sky Upside to Risked NAV**



Source: Company data, Credit Suisse estimates.

EEMEA in 2012, Cautious on Russian Energy

Broadly speaking, we have a cautious outlook on the Russian energy companies, with the exception of NOVATEK (O/P, tgt $175) and Eurasia Drilling (O/P, tgt $32.50) as we believe that these two companies have stand-alone structural growth investment cases that will outweigh the concerns on the macro-environment, cost inflation and stalling tax reform. We have a favorable view on Sasol (O/P, tgt ZAR457) given improving execution and a growing acceptance of GTL technology as a way to monetize the huge gap between gas and oil calorific equivalent prices, particularly in North America and the Middle East.

Cautious on Russia; we favor Novatek and Eurasia Drilling; outside Russia, we like Sasol

Iraq in 2012—Infrastructure and Politics

Significant reserves and some incremental progress on reconciling the federal and regional governments: Iraq and the Kurdish Region of Iraq are seen as the last ‘easy’ onshore ‘underexplored’ oil provinces in the world. Iraq is estimated to hold recoverable reserves of 143bn bbls of oil, while the USGC estimates the Kurdish Region of Iraq to hold 40bn bbls of oil and 60tcf of gas. While the resource attractiveness is luring many oil companies, most recently the Majors entering the Kurdish Region of Iraq, above ground issues between the Government of Iraq (GOI) and the KRG need to be resolved. The Iraqi PM has not quite delivered on the promises to the KRG as a condition to be reinstated following the March 2010 elections, but we generally feel that progress since the creation of a unified government in December 2010 has still been encouraging. It remains to be seen if this progress continues after the US troop withdrawal.

Some incremental progress has been made between Kurds and the Central Government but most will take a wait and see approach after the US troop withdrawal

Export infrastructure needs significant investment: We think it is important to understand the conditions of existing infrastructure and planned expansions across the country. Iraq has three main export routes: (a) the northern distribution system (Kirkuk-Ceyhan) with a nameplate capacity of 1.6mbd (but operable currently estimated at ~800kbd and flows of just c450kbd in 2011, (b) the southern distribution system (Basra Oil Terminal/Khor al-Amaya) with a nameplate capacity of 3.45mbd (but operable capacity closer to 1.8-1.9mbd), and (c) the Kirkuk-Banias (Syria) pipeline (not operational nor likely to be) with a nameplate capacity of 700kbd. All of the export routes operate below nameplate capacity, as infrastructure restrictions do not allow for full operation. Indeed a report from Foster Wheeler in 2007 stated that the pipelines connecting to the Basra Oil Terminal are over a decade past their shelf life (excessive corrosion) and at risk of failing at any time. There is a plan to correct this and debottleneck export capacity through the North, but progress needs to be made to execute this plan or Iraq will not live up to its resource potential.

The pipelines connecting to the Basra Oil Terminal are over a decade past their shelf life (excessive corrosion) and at risk of failing at any time

There is a plan to correct this and debottleneck export capacity through the North but progress needs to be made to execute the plan

Asia Pac in 2012, Stay with the Upstream

In APAC energy security becomes yet more important, with external M&A and exploration in the South China Sea as recurring themes for our stock universe. With crude forecast to stay above US$100/bbl we prefer COSL and CNOOC in China, avoiding ongoing refining losses. In Australia we prefer Woodside, ready to book 20%+ production growth in 2012, along with Origin as it prepares to sanction a 2 train LNG project. In Japan Inpex and Japex both have growth catalysts not yet reflected in the price.

A regional focus on energy security suggests M&A and exploration deep offshore China will be key themes in 2012

APAC theme 1: Asian M&A steps up another gear: The imperative for APAC countries to increase international oil and gas assets continues. We expect Asia to focus on Canadian assets in 2012, among others.

APAC theme 2: South China Sea focus intensifies: 2012 will see a significant increase in deepwater exploratory activity in the un-disputed deepwater South China Sea province, with CNOOC, COSL, Chevron, BP, BG & Anadarko involved.

Australian Oil and Gas in 2012: Cost Still an Issue

Cost inflation as 8 LNG projects hit the construction phase at the same time remains a concern

Outside of LNG, some tests are under way on liquid shale potential

Between Australia and PNG there are 8 LNG projects under construction at present. Additional trains may be added via brownfield expansion at Gorgon, Wheatstone, Pluto and PNG, which are not included below. Additional LNG trains will only increase Australian/PNG LNG output and extend the period of tight contractor resource availability/risk of cost inflation. Echoing the recent launch of our Global Gas report, Australia unsanctioned projects face tougher competition given affordability concerns and lower cost alternatives emerging in East Africa and North America.

Outside LNG, in 2011 we saw an exponential increase in interest in Australian shale gas potential. A number of deals we consummated with Majors buying into various shale plays. We now see BG taking a direct interest in the Cooper Basin shale, COP and Mitsubishi in the Canning Basin and HES in the South Georgina Basin. Very little delineation of the shale potential has occurred, with the only real drilling and frac test being completed by Beach Energy in the Cooper Basin. We expect to see a substantial increase in shale drilling in 2012.

Latin America: YPF gaining ground

We remain concerned over PBR’s growth outlook and highlight the value upside to YPF from Vaca Muerta shale

Within Latin America, we think the *Transition* theme will be evident in 2012, although in two opposite ways: (1) the Brazilian Energy sector is transitioning from a phase of exploration euphoria to development reality for the Pre-salt, and we think this will be illustrated by a production profile from Petrobras that will fail to provide strong oil growth until 2013-2014 at the earliest; (2) The Argentina Energy sector is transitioning to a de-regulation phase, and we are also on a possible new exploration period, with YPF’s recent one billion bbls Vaca Muerta shale discovery being a tangible evidence of the country’s renewed resource potential.

Global Gas (ex-US) in 2012—Tight Markets Favor BG, RDS, and Total

As outlined in our recent major report on global gas markets, we see several themes for international gas markets in 2012 and beyond.

Global LNG market tightening, especially in Asia-Pacific: BG, RDS and Total have the highest share of their upstream production from LNG today and should be the beneficiaries of a tight LNG market from 2012-2015.

LNG projects sanctioning: winners and losers: Unsanctioned projects face tougher competition given affordability concerns and lower cost alternatives emerging in East Africa and North America.

In Europe, weak gas demand puts pressure on oil indexation: European utilities are over-contracted for natural gas due to the weak economy and more attractive economics for burning coal. This is likely to put continued pressure on oil indexation of longer-term contracts.

BioCarbon—What to Expect in 2012

We believe the progress that companies are demonstrating should give investors more comfort that a disruptive revenue opportunity in biocarbon is becoming real and getting closer. Green chemicals from Brazil sugar cane and even cellulosic fuels in the US are on the way to commercialization. As cost structures come down and markets open up, the BioCarbon group could outperform broader markets. At the same time, new entrants and novel approaches will continue to challenge the existing hydrocarbon infrastructure with a biocarbon alternative. Watch this space.

12 Things That May Happen in 2012

A semi-serious list as usual.

1. The Oil Majors splash out on North American liquids-rich shale assets with over $20bn worth of deals, including some surprisingly large Independents.
2. A wave of consolidation sweeps up the smaller players in East Africa natural gas (Mozambique and Tanzania).
3. The Marine seismic market finally spikes in mid-2012 on the back of strong North Sea summer season, bid rounds in West Africa & Brazil, reopening of the Gulf of Mexico, and allocation of more vessels to multiclient surveys
4. Gazprom's oil indexation mechanism is broken by the Stockholm arbitration court in late 2012, marking a key victory for the European utilities. Other midstream players follow by launching their own lawsuits against Gazprom.
5. Shell/PetroChina make a huge shale gas discovery in China, prompting Chinese authorities to raise nonconventional gas production targets to 1/3 of the country's consumption by 2020.
6. The geopolitical battle for control of Iraq intensifies. Pipeline damage in the south leads to the loss of 1.9mbd of exports and a spike in Brent oil prices.
7. Libya, Syria and Yemen struggle to maintain or regain lost output owing to political power struggles
8. In a race to the bottom, policymakers choose printing money (i.e., QE by the Fed, ECB, MPC, and BoJ) to drive down real rates as a way to deal with $8trn of excess leverage driving a rally in oil price levered energy equities
9. Asia energy M&A reaches new peaks as consuming nations consolidate their access to Canadian, Latin American and Africa resources.
10. 1.5 MBD or European refining capacity is closed driven out by weak refining margins.
11. The EPA finds a way to overrule state based hydraulic fracturing legislation slowing the pace of drilling materially.
12. Argentina becomes the hottest international destination for shale and a meaningful addition to global pressure pumping demand.

Our 11 Predictions from Last Year

Our self-graded report card shows us getting less than 50% of our 11 semi-serious predictions for 2011.

1. *After a string of further discoveries, Colombia becomes the hottest emerging oil producer and surpasses 1.0 MMBbl/d by year-end.*

   NO

2. *West Africa sub-salt exploration explodes after a large discovery off Angola. West Africa prepares for giant lease sales.*

   YES

3. *New East Africa gas discoveries in Mozambique and Tanzania total > 30 Tcf. The region starts to rival Australia in the race to launch new LNG export projects.*

   YES

4. *Ten companies announce plans to retrofit North American LNG import terminals into liquefaction plants to reexport gas. The US government launches a study on natural gas 'security' as it seeks energy independence.*

   YES (Partly)

5. *Dozens of speculative newbuilds hit the rig market. In response, the US Contract Drillers try to defend market share and unleash a tidal wave of new rig orders. Day rates collapse.*

   NO

6. *Rising Eurozone concerns cause the US dollar and euro to reach parity. An oil market swoon ensues pushing prices below $60 per bbl.*

   YES (Partly)

7. *The Australian Government loses its mandate and conservative opposition comes in, removing the Minerals tax.*

   NO

8. *Smaller US producers have trouble attracting rigs and services given new larger players. A series of 'mergers of equals' ensues to gain scale.*

   YES (Partly)

9. *The Russian government introduces profit based taxation for new upstream developments leading to Russian oil companies substantially changing medium-term investment plans and material upgrades to production forecasts.*

   NO

10. *A strongly motivated DoJ pursues the maximum criminal penalty against the Macondo spill companies setting the precedent that rig operators are liable under the Oil Pollution Act and that all companies are severally liable for Clean Water Act fines, severely impacting Gulf activity.*

    NOT YET KNOWN

11. *The 2011 Chevy Volt is a hit, sending electricity demand soaring just as the EPA regulates the coal industry out of business. That sparks a rally in US gas prices along the entire futures curve.*

    NO, Only 5k cars were sold and batteries are being investigated after crash-tests

2012 Top Picks Stock Summaries

Integrated Oils

Repsol YPF SA (REP.MC) O/P, TP €27.0/share: We think Repsol is one of the most interesting stories among European integrated oils for the following four reasons: (a) differentiated upstream growth (c5% CAGR over 2009–2020E); (b) a deep exploration portfolio with good resource opportunities including key play openers in the Guyana basin and Angola Pre-salt; (c) a highgraded refining portfolio; and (d) a structural improvement and unconventional upside at YPF. Repsol also has de-geared its balance sheet over the past year and we believe that, with sharply improved cash flow from 2012 onwards following the completion of the refinery projects, the dividend outlook is already attractive (2012E DY of 5.7% with 10% pa DPS growth; sector average of 4.9% and growing at c7% in 2013E).

Royal Dutch Shell (RDSa.L) O/P, TP 2750p, $86/ADR: Best cash flow growth potential in Big-Cap Oils: Shell remains our top pick among European integrated oils. We believe it should deliver the best cash flow growth among large-caps for the next five years (+50% over 2010-15E at $90/bbl vs 38% avg), and provides one of the highest free cash yields. Shell’s three key 2011 upstream projects are on track, with Pearl GTL and Jackpine (Canada oil sands) ramping up well. Shell has delivered a solid performance in 2011, but with little cash contribution yet from the three key projects, pointing to further upside in 2012. Meanwhile, Shell continues to progress its longer-term options for the post-Pearl period, with several project FIDs taken this year (including Cardamom in GoM and Prelude FLNG), supporting its 3.7mbd production target in 2014 (3% CAGR 2012-14E).

BG Group plc (BG.L) O/P, TP 1770p: Return to growth and LNG upside: We have added BG to our most preferred list as we believe BG is well-positioned to benefit from a tightening global LNG market thanks to its flexible LNG portfolio (see *Global Gas: From tight to loose by 2016*, 22 November). Upstream production growth is also set to rebound in 2012 after a lacklustre two years. We would expect the February 2012 strategy presentation to be a positive catalyst for the shares, as the company should give updated guidance on (i) LNG earnings (we see upside to 2013 LNG estimates as the price hedges will roll off) and (ii) Brazil development plans. Further catalysts should come from (i) drilling updates in Tanzania (BG needs c.8tcf to sanction a two-train LNG project, worth c.43p /sh) and (ii) the sanction of a third LNG train in Australia (worth c.74p/sh).

Occidental Petroleum (OXY) O/P, TP $135/sh: Occidental Petroleum (OXY) is being added to our large cap top picks for the next 12 months after the relative share price pull back. OXY offers 5-7% volume growth plus a 2% dividend plus a 5% free cash flow yield over and above the capex and dividend. OXY’s growth is being de-risked by higher rig counts in the Permian and California. OXY expect to add 5 rigs every 6 months in California and wells in this play generate some of the highest returns available globally in oil.

Chevron (CVX) O/P, TP $130/sh: Chevron (CVX) continues to be a core longer term holding. CVX generates the strongest current returns in the majors and yet the shares discount a large compression of returns due to a lack of near term growth and their capital cycle. The multiple has been compressed due to rising capital spend, notably in the Gulf of Mexico and Australia. More recently, the shares have been overly punished underperforming by $13bn relative since a 3,000 bbls leak at Frade was announced. We expect CVX to pay fines to the government and damages to local fisherman, but not nearly of this scale. Currently our TP is only $130/sh due to high upfront capital spend. However, CVX offers more upside over time than peers, as this high capital spend is translated into cashflow.

Refiners

Marathon Petroleum Company (MPC) O/P, TP $63/sh: Despite Q4 EPS headwinds, MPC offers strong mid-cycle operational free cashflow. Importantly, just the cashflow from Logistics and Speedway covers MPC's maintenance capex and dividends. This reinforces MPC as a defensive play in US Refining. We believe management are considering higher return of cash to investors via dividends. MPC's Garyville refinery has been de-bottlenecked to run 50% above it design capacity. MPC should have $300-400M additional EBITDA when DHOUP is on-stream in late 2012. MPC has recently outlined opportunities to debottleneck plants, improve diesel yields, capture more WTI crudes (currently 35%) and capture low hanging fruit in Retail - all high payback projects that are not yet factored into medium term earnings consensus.

Western Refining (WNR) O/P, TP $20.5/sh: WNR sold off noticeably since the Seaway pipeline reversal announcement and on seasonally weak Q4 West Coast/Gulf Coast margins. Despite Q4 seasonal earnings risk, the sell-off is overdone. The company is paying down debt having sold its Yorktown terminal/other nonproducing assets for $220m, which should be accretive to multiples. Overall cash flows in 2012/13 are relatively better protected from Euro debt crises given the crack spread hedging program in place. Strong free cash flow and disposal proceeds will help achieve managements no.1 priority—to pay down debt (target total debt is $500-600mn—as of 3Q11, total debt stood at $1.06bn). Small investments to increase local crudes into the El Paso refinery and maybe expanding Gallup next year should also pay good dividends. An expansion of the El Paso refinery is a medium-term possibility.

US E&Ps

HESS (HES) OP, TP $115/sh: Hess Corp (HES) remains an attractive investment vehicle and we update our rationale for maintaining it as a top pick over the next 12 months for three key points: 1) free cashflow will improve. HESS is outspending cashflow in 2011-2012 owing to upfront costs in Bakken and offshore exploration. As we move into 2013 and particularly 2014, free cash generation will improve. HESS have a $4bn revolver so their 2012 outspend is manageable. 2) HESS have a significant exploration catalyst calendar with the 1st well in Utica (likely released at FY11 results), a giant 2 billion barrel high risk Semai V gas wildcat (January), Ghana (rig arrives February) and Brunei wildcat (results in January). And 3) HESS has a number of noncore assets for sale as it repositions its portfolio which should help offset near term cash shortfalls. If HESS manage to close the HOVENSA refinery and thereby avoid cash losses, then 2013 cashflow could rise by $500M (if we also include a roll off in hedges) without any help from the macro environment or underlying upstream growth.

Rosetta Resources (ROSE) O/P, TP $68: ROSE recently reaffirmed its 2012 production guidance range of 220-240 MMcfe/d, with more than 90% of its planned $640MM capital budget targeting the Eagle Ford, which we argue provides among the best project returns in domestic onshore E&P. At the futures strip, 2012 capex is roughly $125MM ahead of projected cash flow, but with $100MM in cash and $300MM available on its credit facility at the end of 3Q11 no external sources of capital are required to fund the budget. We expect ROSE to deliver production and cash flow growth of 34% and 63%, respectively per year through 2013 vs. the CS SMID-cap E&P peer group median of 16% and 53%. ROSE had success in both its Gates Ranch infill program and its exploratory program outside the Gates Ranch increasing its Eagle Ford drilling inventory to almost 500 locations (~280 in Gates Ranch and ~200 in new exploratory areas) from approximately 210 in 2Q11. Notably, at the current pace of development ROSE has roughly an eight-year project inventory and the company still has an additional 10k net acres in the liquids window of the play yet to delineate.

Energy XXI (EXXI) O/P, TP $40: EXXI is a top pick in the E&P group given projections for strong free cash generation, a deep inventory of low-risk development projects that should continue to drive growth and the cheap imbedded option on the Ultra Deep shelf play that ultimately could make EXXI the low-cost gas provider in domestic E&P. We project EXXI will generate $1.2 billion in free cash over the next three years, which would position EXXI to fund additional acquisitions and potentially accelerate development and exploration activity. In addition, this cash flow generation would allow EXXI to potentially return cash to shareholders in the form of a stock buyback or dividend.

Swift Energy (SFY) O/P, TP $46: SFY formally raised Eagle Ford well recoveries and project economics at the end of September 2011, and we estimate the liquids window of the Eagle Ford provides the company with a project inventory with an undiscounted NPV of $3.6 billion compared with the current enterprise value of only $1.8 billion. Considering SFY also has 44k net acres in the liquids-rich Olmos, 50k net acres in a JV with APC in the Austin Chalk, as well as the company's Southeast Louisiana conventional oil inventory, the company is not short of liquids-rich development opportunities. SFY expects to deliver 20-25% production growth in 2012 driven by a $575-625 million capital budget, which at the future strip (assuming 24% production growth and midpoint of capex guidance) would equate to roughly a $190 million gap between cash flow and capex. With a recent high-yield offering ($250 million in senior notes due 2022) and an untapped $300 million credit facility, SFY has ample liquidity to fund this budget.

Cobalt (CIE) O/P, TP $17: With two industry successes in a row (and the third in total for the Angola Pre-salt) it is early but very encouraging times. Cobalt alone could have net unrisked mean reserves of over 5bn boe on its Angola Pre-salt blocks 9, 20 and 21. Rock quality is the key determinant of success—we should have the results of the first flow tests from Cobalt imminently. Although Cobalt shares have rallied by 50% since the announcement, unrisked potential is over $40/sh. Beyond the Angola Pre-salt, Cobalt has a large acreage position in the Gulf of Mexico and exposure to the Gabon Pre-salt. Outside Angola, key wells in 2012 include Heidelberg appraisal, Ligurian, North Platte, Ardennes and Aegean in the Gulf and Pre-salt drilling on the Diaba block in Gabon. In Feburary 2011, DeGolyer and MacNaughton, a reserve auditor, estimated Cobalt's West Africa portfolio with over 60 Pre-salt targets to contain up to 7.6bn boe of net unrisked mean prospective resources while the Gulf of Mexico is a not insignificant 3.3bn boe. The shareprice may have rallied but there is more upside to play for as drilling de-risks the portfolio.

Kosmos Energy Ltd. (KOS) O/P ,TP $25: Although much of the exploration excitement has shifted recently to Angola, Guyana and the Gulf, KOS offers investors a focused opportunity for Ghana resource exploration upside in 2012 funded from existing cashflow. In a risked outcome, KOS 2P resources could rise by 60% through 2012 from Ghana alone. Looking beyond Ghana, KOS has built a prospective acreage position in Cameroon and Morocco for 2013 drilling and recently acquired 3million gross acres offshore Suriname (to be drilled in 2014). KOS shares trade at a discount to the value of already discovered resource, a good risk-reward tradeoff.

European E&Ps

Premier (PMO.L,) O/P, TP 490p—Growth at a reasonable price: With a strong balance sheet and some key headwinds removed recently (Huntington FPSO / Catcher partner issues resolved), the stock looks too cheap to us at a 24% discount to risked NAV, given the 16% p.a. production growth. Over the next five years, we expect production to increase to 100kboepd as it brings 10 additional fields on-stream. Premier is currently trading 17% below our Core NAV of 439p/sh. The share price is embedding a flat long-term oil price of only $91/bbl on Core NAV and, when we include our view on exploration, $84/bbl on Risked NAV. Cash flow growth looks set to average 12% p.a. to 2015E, underpinned by strong cash generation from Asian gas (realized Singaporean gas price was $18.5/mcf in 1H11).

Tullow (TLW.L) O/P, TP 1776p—Still busy 'elephant hunting': The depth of Tullow's exploration portfolio remains unparalleled in the UK E&P space, in our view. Despite the slower ramp-up on Jubilee, we are convinced that Tullow continues to progress into a better-capitalized version of its previous self, underpinned by strong cash flows in Ghana. Tullow's balance sheet continues to evolve, and with the $2.9bn of Uganda farm-out proceeds expected shortly, we believe Tullow will be in a comfortable financial position to reinvest into exploration; a portfolio that is highly admired and material enough to make a difference to a company the size of Tullow. Tullow has a significant portfolio of exploration catalysts next year that could drive material NAV accretion of c600p if successful. Several play opener wells are planned in the near term, and for potential 'elephants' we look to Jaguar in Guyana due to spud in December (+58p/sh potential), Jupiter and Mercury in Sierra Leone (+21p/sh potential) in Q4, and two wells in Cote d'Ivoire (+86p/sh potential) early next year. Tullow trades at a 25% discount to risked NAV of 1,776p/sh.

Ophir (OPHR.L) O/P, TP 510p—Frontier exploration in the right geological "postcode": We reiterate our O/P ahead of the transformational drilling campaign with a TP of 510p. The 9-13 well drilling program is worth 238p/sh on our risked NAV with an upside of 679p/sh. Recent successes in areas of Ophir's portfolio are attracting significant industry interest, and this is important as Ophir is likely to be looking to monetise (complete sale or partial farm-out) its acreage in Tanzania and Equatorial Guinea as early as 2H12 after what will be an important drilling program in 1H12. Also, Ophir remains fully funded until early 2013E with c$410m of cash. The potential for LNG in Tanzania and EG is central to Ophir's investment proposition (this is our key theme for the year), and it plans to drill several high-impact wells to prove foundation volumes to underpin LNG developments.

Genel (GENL.L) O/P, TP 1093p—A pure play on the Kurdish region of Iraq: We view Genel as one of the few self-sufficient companies in the Kurdish region of Iraq, with a strong balance sheet and a highly experienced management team that can drive shareholder value creation. It has a distinct first-mover advantage to access infrastructure and a large portion of its value comes from fields signed pre-constitutionally, which therefore should not be subject to amendments. We believe Genel can generate superior returns, organically via the drill bit and inorganically from its c$1.9bn of cash (via accretive M&A), and the strength and experience of management support our view. We see Genel as a lower-risk, less volatile way of gaining exposure to this emerging oil region. With a clear growth strategy, Genel is an attractive proposition for long-term investors.

Det norske (DETNOR.OL) O/P, TP NOK120—Det norske currently qualifies as growth at a reasonable price with a 'free option' on potential M&A upside, in our opinion: Reasonable price, because the shares are currently trading 33% below our risked NAV of NOK 120/share; Growth, because resource upgrades can continue to come through for Det norske from its active 2012 drilling program. Despite the c.150% increase in Det norske's share price following the Avaldsnes/Aldous discovery, we think the shares will re-rate further with additional reserves unlocked through the 'drill bit' (+NOK 80/share blue sky upside potential from 2012E drilling). With the fourth largest holding of undeveloped resources on the Norwegian Continental Shelf, including a stake in the giant oil field—Avaldsnes/Aldous, we believe Det norske also offers a 'free option' on potential M&A upside.

Australia and Japan E&P

Origin Energy (ORG.AX) O/P, TP AU$16.90:–Current valuation under-pinned by existing business, 2nd LNG train will now proceed after Sinopec agrees to purchase an additional 3.3 mn Tpa and acquire a further 10% equity stake. ORG:AU's underlying business (mainly low risk integrated utility) is underpinned by AU$14.29/share valuation, excluding 37.5% APLNG interest.

Oil Search (OSH.AX) O/P, TP AU$7.40: 2012 contains some risks for OSH:AU, including peak construction phase for the 2 train PNG LNG project, and PNG government elections in June. However the XOM-led JV will also drill a number of high impact gas wells to prove up reserves for a 3rxd LNG train. With the level of overinvestment in the infrastructure for trains 1 and 2 and the high level of liquids, train 3 is the most economic brownfield LNG expansion project in APAC. The key positive event is an appraisal well in the Hides gas field, expected to delineate the gas-water contact in the field, and is due to spud in 2Q12. The JV;s position on train 3 gas reserves should be announced to the market by late 2012. A de-risked train 3 takes our valuation for OSH:AU to AU$9.00/share.

Woodside Petroleum (WPL.AX) O/P, TP AU$42.5: (We believe Woodside could rebound after a difficult 2011. The share price suffered owing to Pluto cost overruns and delays, Browse LNG evaluation delay, concerns over Shell's stake in the company and general concerns over LNG capex in Australia. As Pluto finally comes on stream, the market could start appreciating the cashflow potential of the company and the potential for the new CEO to leverage Woodside's strengths into new upstream investments outside Australia.

INPEX (1605 JP), Outperform, Y700,000: INPEX should be a winner, in our view, because 1) INPEX can benefit from increased gas demand in Japan by developing two LNG projects (Ichthys and Abadi). 2) INPEX is financially sound and has strong backing from utilities, 3) INPEX's valuation is one of the cheapest among global E&P, on our forecasts.

Canadian Oil and Gas

Suncor (SU.TO) O/P, TP C$50: Suncor is targeting 1 million boe/d of production by 2020, representing 10% production CAGR 2000-2020, supported by 7.2 billion barrels of 2P reserves and ~20 billion bbls of contingent resources. This growth is fund by internally generated cash flow, mainly flowing from Petro-Canada assets as a result of its merger with Suncor. With ~300 kb/d of ‘inland’ refining capacity, Suncor benefited from ‘supernormal’ Mid-Con refining margins. But with ~68% of Q311 Downstream EBITDA generated by the Brent–WTI spread, we see that EBITDA as being transitory between Suncor’s Downstream and Oil Sands business.

Penn West (PWT.TO) O/P, TP C$27: Penn West’s strategy to maintain its dividend and grow value through increased liquids production and 4-6% production growth is getting back on track, following a difficult year operationally in 2010. Incremental netbacks on light oil should drive superior CFPS growth vs. peers. Penn West is a good way to play further narrowing of the Brent-WTI spread.

US Oil Field Services and Equipment

Baker Hughes (BHI) O/P, TP $77: BHI is our top diversified services idea for 2012. We are more confident in its US exposure (62% of BHI's 2012E earnings) than historically discounted current multiples imply and are confident in its ability to continue to realize efficiencies in its pressure pumping business. We are also confident regarding medium term growth outside NAM based on business development success, including offshore opportunity in Brazil and Southeast Asia/Australia. Furthermore, BHI lacks the near-term headline risks surrounding the Macondo disaster, which is relevant in our relative preference over similarly positioned Halliburton.

Cameron (CAM) O/P, TP $71: CAM is our top pick within our equipment coverage. We have become more encouraged over the last month by signs of meaningful order growth in 2012 across several of CAM’s product lines, including (1) Subsea, including that PBR appears to be moving ahead with what could be $1B awards for both FTI and CAM by early 2012; (2) Process Valves, directed toward Russian refinery upgrades; (3) Engineered Valves—we suspect chunky subsea and still pipeline valve opportunities; and (4) Processing Systems, related to PBR FPSOs, Malaysia CO2 separation as well as more generally. Coupled with reduced Macondo liability risks following CAM's settlement with BP and a renewed $500 million share repurchase program give us confidence in shares in 2012.

Ensco (ESV) O/P TP $71: ESV remains our top pick among the Offshore Drillers. We believe the company is in the rig availability 'sweet spot' given exposure to key markets that are seeing a strengthening in dayrates, including the US GoM, Mexico, Southeast Asia and the North Sea. And the company also has one final 8500 series newbuild as well as the DS-6 newbuild drillship that are uncommitted, giving it exposure to the tight ultra-deepwater market in 2012 as well. While ESV's track record has not been perfect, execution and cost control remain better than at peers such as RIG and NE, and ESV's, which raises comfort in the expected earnings stream from the ongoing 8500 newbuild series.

Oil States International (OIS) O/P TP $110: OIS is our top pick among our small/mid-cap names within our coverage. We believe shares of OIS are poised to break-out to even higher levels driven by strength in Accommodations, Offshore Products, and other Well Site Services. Accommodations are OIS' key growth driver and are highly levered to the Canadian Oil Sands and Australia's mining sector—both primed for secular upswings due to their vast natural resource reserves. Mounting natural gas and other mining projects in Australia and expanding oil sand development in Canada should support further Accommodation growth (50% of TTM EBITDA) in 2012 and beyond. Offshore Products should also benefit from the ongoing secular growth trends to more subsea and deepwater exploration.

Precision Drilling (PDS) O/P, TP $16: PDS is our top pick within our onshore drilling coverage. We sense that Canada can offer upside to 2012 estimates largely on stronger than modeled utilization. And we think PDS has positioned itself well for the US There is no doubt PDS is positioned aggressively. It is seeking to grow its newbuild rigs and would consider expanding its capacity to do so at the same time as it is pursuing its directional drilling business and seeking to redirect rigs and build new ones for the Middle East and Eastern Europe. Yet we have confidence in its in-house capabilities to manage its fleet and thus are more comfortable than not that it can handle its growth ambitions.

GEM Oils

Eurasia Drilling (EDCLq.L) O/P, TP $32.52—Building momentum: Eurasia Drilling remains one of the strongest structural growth stories in the EEMEA energy universe, in our view. We expect Eurasia Drilling to post EPS CAGR in excess of 20% for the next four years as it benefits from Russian oil companies' need to drill more to sustain current production levels, as it boosts margins by continuing to deliver operational efficiencies and as it grows its exposure to the exceptionally strong offshore Caspian drilling market. Drilling activity has been strong in 2011 thus far, with volumes up 15% in the first half yoy. We believe that EDCL may start to enjoy some pricing power in its Russian onshore drilling operations by 1H12, a facet unseen in Russian oilfield services for almost four years. We think that recent margin compression should be offset by stronger revenues, that corporate governance concerns are overdone and that Eurasia Drilling may announce new offshore Caspian Sea projects in the near term.

NOVATEK (NVTK.RTS) O/P, TP $17.1—Winning market share: We believe that NOVATEK will continue winning market share from Gazprom, as the accelerated growth of domestic gas tariffs drives Russia's domestic gas consumers to seek more competitive supplies. We also believe that NOVATEK will be able to continue the chain of value creative acquisitions (stakes in Sibneftegas and Severenergia were acquired at EV/boe reserves valuations of between $0.50-0.75/boe versus the typical transaction valuations of c.$2/boe in Russia) as we believe there are many other lucrative potential targets such as Nordgas and Purgas. We believe that the recently announced intention to acquire 25% of the German gas utility, Verbundnetzgas, could be a precursor to NOVATEK exporting gas from Russia to Germany. This would be a profoundly significant move as it would imply the breaking of Gazprom's monopoly and would substantially boost NOVATEK margins. We believe news on new acquisitions of gas assets or JVs with oil companies would also be a positive catalyst for the stock. Currently NOVATEK is trading at a 20% discount to its five-year average valuation, despite a 30% EPS CAGR for the next 4-5 years.

YPF Sociedad Anonima (YPF) O/P, TP $50/ADR: What we ultimately like about the YPF investment case is a combination of (i) earnings growth, enabled via the trend for domestic fuel prices to increase, (ii) resource potential in Argentinean shale (and Guyana), (iii) savvy cash-flow management allowing a sector leading 10% dividend yield, and (iv) improving recovery factors that could sustain current production levels for over 15 years, which puts YPF's apparently low reserves life of five years in the context of low investments in recovery over the last decade.

COSL (2883.HK) O/P, TP HK$16.80: Near-term beneficiary of deepwater exploration activity in South China Sea—30% earnings growth in 2012 driven by already contracted delivery of semi-subs in Norwegian North Sea & its geophysical segment.

Energy Infrastructure

Boardwalk Pipeline Partners, LP (BWP) O/P, TP $35: BWP's distribution growth has stalled over the last several quarters owing to headwinds from higher integrity and maintenance expenditures, contract rollovers, and weak natural gas fundamentals. The surge in natural gas supplies from unconventional sources has reduced ancillary profit opportunities from storage and park and lending services. However, longer-term natural gas demand from power generation is likely to enhance storage fundamentals due to seasonal load requirements, in our view. BWP is pursuing new growth opportunities in natural gas gathering and processing as well as in other energy infrastructure businesses in order to spur growth. To this end, BWP's new President and CEO, Stan Horton, has a breadth of experience across energy sectors that should be helpful. In the meantime, investors should realize an attractive total return given BWP's relatively high current yield and modest distribution growth. We continue to rate the units Outperform.

DCP Midstream Partners (DPM) O/P, TP $51: DPM is a natural gas- and natural gas liquids-focused MLP with a diversified geographic footprint. DPM is well positioned to drive stable long-term growth, given its (1) sponsor's growth profile and large portfolio of assets that can be sold to DPM over time, (2) investment-grade balance sheet and liquidity that enable DPM to fund acquisitions and expansion projects, and (3) primarily fee-based or hedged margins that mitigate commodity price exposure. We believe consistent quarterly distribution growth is set to resume at DPM and expect distribution growth to accelerate to an annual range of 5-7% beginning in 2011. This distribution growth coupled with DPM's current yield of 5.7% provides an attractive total return proposition of 19.7%, in our view.

El Paso Pipeline Partners, LP (EPB) O/P, TP $41: EPB is well positioned to drive long-term distribution growth, in our view, given its (1) sponsor El Paso Corp. (EP) has a large portfolio of natural gas pipeline and related assets that can (and we believe will) be sold into EPB over time (2) fee-based contracts that mitigate direct commodity price exposure, (3) ample liquidity and proven capital market access to fund growth, and (4) predictable excess cash flows which would support further dropdowns. Based on our forecasts, we believe EPB can drive a distribution CAGR of 9.4% over the next five years, one of the highest among master limited partnerships within our coverage universe. We maintain our Outperform rating.

Targa Resources Partners, LP (NGLS) O/P, TP $42: We expect NGLS to realize strong distribution growth, driven by strong natural gas processing economics and attractive organic growth projects. Increased drilling activity around liquids-rich shale plays is necessitating the need for additional infrastructure to gather and process natural gas, transport the gas and natural gas liquids (NGLs) and fractionate the NGLs into purity products. NGLS owns and operates assets well-positioned in this midstream value chain, and has currently identified significant organic growth opportunities. We are confident that the partnership will be able to secure additional projects and consummate accretive acquisitions, which should enhance its distribution growth profile.

Capital Power Corp. (CPX.TO) O/P, TP C$28.00: Capital Power Corp. (CPX) is a Canadian independent power producer with majority of its generation assets situated in the province of Alberta, which is second only to Mexico in terms of projected average annual demand growth, according to NERC. We view Alberta's near-term power pricing dynamics as favorable. CPX has a relatively young generation fleet compared to its Canadian peers. The company's Alberta production is hedged roughly 40% and 15% for 2012 and 2013, respectively. The lower hedged position allows the company to benefit from upward movements in power prices. Capital Power also pays a solid dividend at a yield of roughly 5.0%. The company maintains an investment grade credit rating with low near-term debt maturities. Lastly, the company has ample near-term organic growth.

US Utilities

Edison International (EIX) O/P, TP $48.00: We think EIX’s share price fails to reasonably value the regulated utility Southern California Edison, let alone option value for EIX’s merchant generation business, Edison Mission (EME). In EIX shares today investors can buy a utility growing EPS at 6% annually (even assuming a 75 bp ROE cut) with still best in class regulatory protections at a discount to peers on traditional P/E and offering the best annualized Rate of Return potential for Regulated Utilities at 11.0%. We see catalysts for EIX coming with (a) resolution of the pending utility rate case in 1Q12 (b) final decision on the Homer City Power plant that we expect EIX to walk away from but certainly to not allocate additional capital and (c) comprehensive decision on financial viability of the Edison Mission merchant generation subsidiary in late summer/fall 2012; either management will demonstrably show positive equity value or walk away, either of which is positive versus the negative value currently embedded in EIX shares.

CMS Energy (CMS) O/P, TP $25.00: CMS continues to be a favorite mid-cap regulated utility offering (a) visible 5-7% long-term EPS growth (b) commitment to growing its dividend with a 9%+ increase possible in January 2012 (c) no block equity through 2015 and (d) supportive regulatory environment. We believe Michigan will be recognized as a premium regulatory state in 2012 with the Commission granting fair ROEs and demonstrated willingness to empower utilities to earn their allowed ROEs - something emphasized during our recent trip to meet with the Commission and companies.

Oil Market: Macro Context & Outlook

In essence, we expect the macro environment of 2012 to look very much like what the second half of 2011 looked like. It's only later this year that the broader economic environment begins to improve more sustainably. This will likely be another year of two halves. Transition will, we hope, be the theme of 2012.

Demand dominates the headlines but watch supply risks carefully

In this chapter, we discuss our base case oil demand and supply outlook; the intricacies of our demand scenarios; three categories of supply side risks; the state of fundamentals at the end of 2011 (and how they differ from the fundamentals world of mid 2008) and lastly we'll reiterate our view of the medium term (and how clearly visible scarcity in the 2013-15 time-frame may evolve into an era of less stressed markets by the end of this decade).

Exhibit 26: 2012 balance scenario

	Base Forecast	Bearish Diff to Base
Demand (in mb/d)	91.4	-1.4
Supply (in mb/d)	91.4	-0.5
YoY call on Opec + stck	0.3	-0.6
Brent Fct (in $/b)	105.00	80.00

Source: Credit Suisse Global Commodities Research.

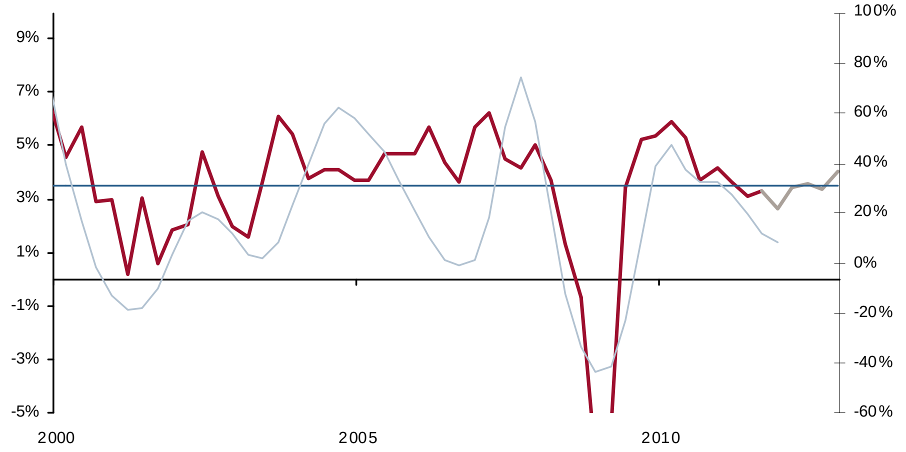
Our (Optimistic?) Base Case Explained

A bigger list of themes about the 2012 oil market has to include key words that our macro-economists use, half of which sound depressing: Divergence, Financial Fragility, Growth and Policy Pessimism. Our house view of the global economy adds up to +3.4% real GDP growth globally in 2012.

$100/bbl Brent in H112 rising toward $115/bbl in 2013

Exhibit 27: Brent Prices vs. Global GDP Growth

Brent trend quarterly price change, GDP qoq change saar forecasts



Source: the BLOOMBERG PROFESSIONAL™ service, Credit Suisse.

In oil supply and demand terms, that means enough oil demand growth to allow for expanding production from Opec and non-Opec sources without rebuilding too much inventory. Put different, oil prices would move sideways to slightly lower as global economic performance traces through the bottom of this cycle, before beginning to recover and driving oil prices sustainably higher from mid-year onward. Average Brent oil prices in our central case come to $100/b in the first half and $110 in 2H2012, for an annual average of $105/b, which would be ~5% down on 2011.

To frame our view of oil prices going forward, we take greater than normal direction from the broader economy. It's clear that the relative performance of oil prices tracks more or less neatly with real economic global growth. That relationship has obviously been especially tight through the Great Financial Crisis of 2008 and the subsequent sluggish and disjointed recoveries in different regions.

Already, the base case incorporates a relatively dim view of Europe's economy. What's worse, we have seen grave risks to the downside grow recently. Here is how our macro economists framed that risk a little more than one month ago:

"Failure to counter the deflationary tide starting to rip through the euro zone's defenses would likely have devastating consequences for systemic stability and global growth …Are we about to suffer wealth destruction on a scale not seen in peace time since the 1930s? …These are not computable risks, leaving the world awash with cash and short of confidence about where, how and when to put it to work.[Having said that our economists offer two judgments to build up our base case:]

- *In the end, Europe's politicians … will pull back from the abyss of deflationary collapse in a region producing close to one quarter of the world's GDP*
- *To do so, they will need to forge what one might call a pre-nuptial agreement on fiscal union linked to transitional funding for Italy, Spain and Greece that will dispel the most immediate doubts about the Euro zone's future.*

[they then continue:] *"Beyond that, however, lies an epic struggle between the forces of money and credit, as the world's leading central banks—including the ECB—deploy their unique powers to contain credit stress and make possible the wrenching adjustments to payment imbalances sovereign debt burdens, and new financial regulations that lie ahead.*

We don't expect it to be pretty or easy, but if they are ultimately successful in 2012, they will be preserving the option of prosperity, employment, and progress for a whole generation, in the developed and emerging market alike."

In practical terms, we as a house expect to see an uneasy dynamic between credit market stresses and central bank intervention across the so-called developed world, which continues to struggle with the need for massive de-leveraging. In the emerging market universe we see, by contrast, more or less "normal" economic cycles and monetary responses playing out. And in this emerging market context we see monetary-policy easing beginning in several key economies, including China and Brazil.

In sum then we agree with our macro house view that we will see "*massive policy intervention"* this year, and with that, sadly, continued low-conviction behind our base case and forecast.

Which is also why we went through elaborate lengths to pull together a bearish scenario, spelling out what would happen to oil demand in case of policy failure in Europe (combined with spill-over effects in other markets and globally).

Oil demand scenarios in numbers

In our experience, most of the attention of and uncertainty among market participants continues to reside on the demand side. We'll focus on that part of the equation first, but

Exhibit 28: **Demand Scenarios**

Demand (in mb/d)	**2012 Avg.**			
	Global	**Europe**	**US**	**China**
CS Base Forecast	**91.61**	**15.07**	**19.03**	**10.36**
GDP Ann. Growth Est.	3.40%	-0.50%	2.10%	8.00%
YoY Growth (in mb/d)	1.65	-0.03	-0.16	0.57
YoY Growth (in %)	1.84%	-0.21%	-0.84%	5.79%
Bearish Scenario	**90.25**	**14.13**	**18.83**	**10.26**
Assumption	-150bp GDP	-2 □	-100bp GDP	-100bp GDP
Net Diff	-1.36	-0.93	-0.20	-0.10

Source: Credit Suisse Global Commodities Research. Note : Scenarios are run by region and globally separately, numbers might not add up.

should point out that oil *supply* has consistently delivered the greater surprises and dislocations in the past twelve months. We fully expect that supply risk will again prove greater this year.

To frame the discussion about oil demand we will explain first our model's findings on the intimate link between GDP and seasonally adjusted oil demand on a global level. We'll explain the assumptions by region that go into this model. Then we'll discuss variations from that base in terms of GDP growth differentials, globally and separately for what we think are the key regions: Europe, US, and China.

Our differentiated view of oil demand

Global Oil Demand Scenarios

Base case: Theme is divergence. Think divergent growth paths.

We have replaced mid-2011 fears of a synchronized global recession with "a more nuanced speed up scare for the US, and increasingly realized "soft landing" for China, and a more intense slowdown scare for Europe." *[Global Economy: Monthly Review: De-synchronizing the global economy, Neil Soss et al.].* In short, we expect a recession in Europe, not globally.

How does our model work? In our approach we work scenarios to our model, which historically tracks actual global demand fairly neatly (see Exhibit 4). (elevated R-square). Our model estimates oil demand seasonally adjusted as a function of GDP levels and quarterly GDP changes over the past two periods.

We run a regression on seasonally adjusted oil demand series from 1Q02 to 3Q11 and then use the output of the models to forecast oil demand in 2012 applying quarterly GDP forecasts from our colleagues in economic research

We then take the delta that the model implies and apply that delta to real oil demand in 2011.

In our model we also correct for the impact of the great recession on historical seasonal adjustment exercises in Europe and the US (because the GFR distorts the historical European and US GDP series too much).

Globally, our base case, using a real GDP growth of 3.4% in 2012, implies a yoy growth of 1.46 mb/d (1.63%) in 2012, that is 91.36 mb/d of oil demand in 2012

Our model is presented as:

OD_sa(t)= **C1** * GDP_level(t) + **C2***GDP_change(t-1) + **C3** * GDP_change(t-2) + **C4**

With OD_sa(t): Oil demand seasonally adjusted at quarter t

GDP_level(t): GDP level at quarter t

GDP_change(t): GDP % change from quarter t to quarter t-1

C1, C2, C3 and C4, four constants determined by the model

For further statistical results, please contact us

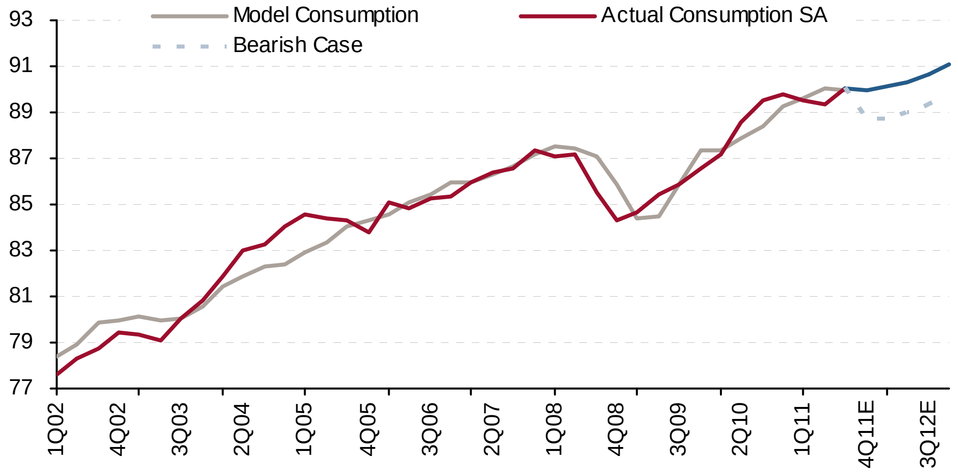
Bearish case: European Meltdown and Spill-Over Effects

We arbitrarily ratchet down global economic growth by 150bps for two broad reasons.

- One, 150 bps reflects better a complex scenario involving a 'meltdown' in Europe and its spill-over effects into other regions.
- Second, taking 150bps from our base case yields globally growth of ~+2% which we find roughly corresponds historically with the zero-growth line for oil demand.

In our model, 2% real global GDP growth in 2012 would equate with 1.36 mb/d less oil demand than in the base case, and a net 100 kb/d decline in demand relative to 2011 to 90.0 mb/d in 2012

Exhibit 29: Global Oil Demand Scenarios



	Base	Bearish
Oil Demand in 2012	91.50 mb/d	90.14 mb/d
Assumption	3.40% ann. GDP growth	- 150 bp
Net diff. from Base	-	-1.36 mb/d
Yoy growth	1.61 mb/d (1.79%)	0.25 kb/d (0.28%)

Source: Credit Suisse Global Commodities Research.

Separate and Distinct Scenarios by Region: Europe

Base case: Recession in Europe

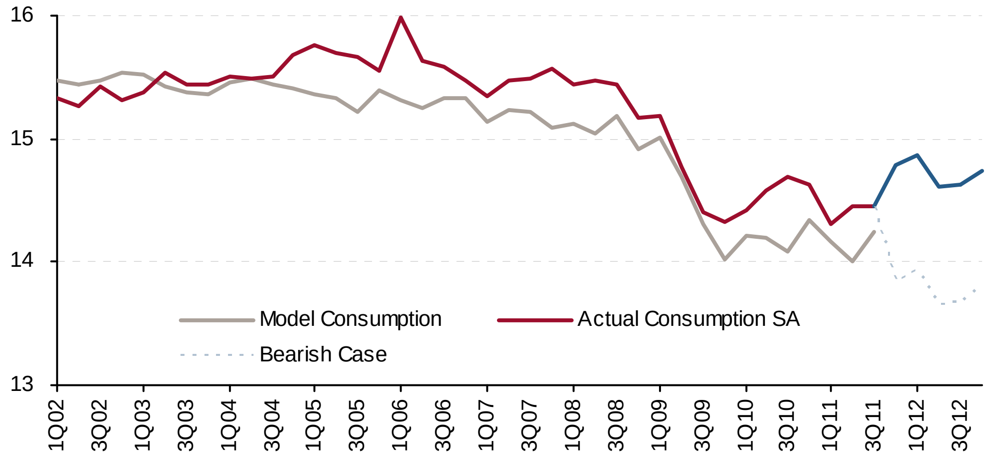
As described earlier, we expect a recession in Europe in our central case with European GDP (including the UK) set to contract by -0.5%, from an already anemic level of growth for the EU in 2011.

In Europe, our base case expects a yoy growth of -0.03 mb/d (-0.21%) in 2012, that is 15.12 mb/d of oil demand in 2012

Bearish Case: Europe Crisis Worsen

There are legion different 'worse case' scenarios involving Europe's sovereign indebtedness, fragile banking sector, slow moving ECB and precariously balanced political power-bases. Most all of them are literally unpredictable in how they'd play out. So we reversed the exercise and assumed in our bear case that oil demand would contract by a statistically significant (but not absurd) 2 standard deviations—which our model says equates to about 0.9mb/d from a base to 14.18 mb.d in 2012.

Exhibit 30: **European Oil Demand Scenarios**



	Base	Bearish
Oil Demand in 2012	15.12 mb/d	14.19 mb/d
Assumption	-0.50% ann. GDP growth	- 2 standard deviations
Net diff. from Base	-	-930 kb/d
Yoy growth	-30 kb/d (-0.21%)	-970 kb/d (-6.37%)

Source: Credit Suisse Global Commodities Research.

Separate and Distinct Scenarios by Region: US

The base case: The US continue to see sluggish recovery in 1H12.

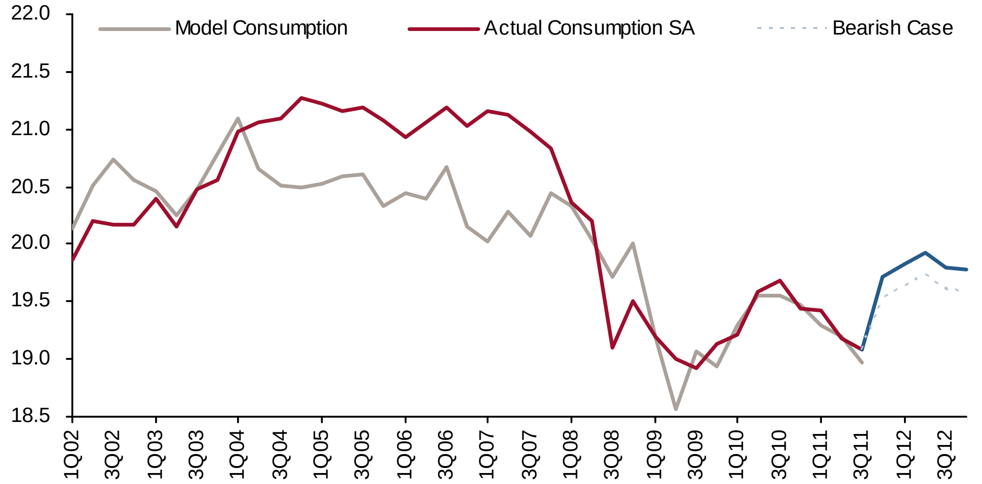
As described earlier, we expect a sluggish recovery in our central case with US GDP set to grow by 12.1%. In the US, our base case expects a yoy decline of -0.16 mb/d (-0.84%) in 2012, that is 19.03 mb/d of oil demand on average in 2012

Bearish case: Europe debt crisis impacts US even further

We arbitrarily ratchet down US economic growth by 100bps as it reflects better a complex scenario involving a ‘meltdown’ in Europe and its spill-over effects into the US.

In our model, this would equate to 200 kb/d less oil demand than in the base case, and a net 360 kb/d decline in demand relative to 2011 to 18.83 mb/d on average in 2012

Exhibit 31: **US Oil Demand Scenarios**



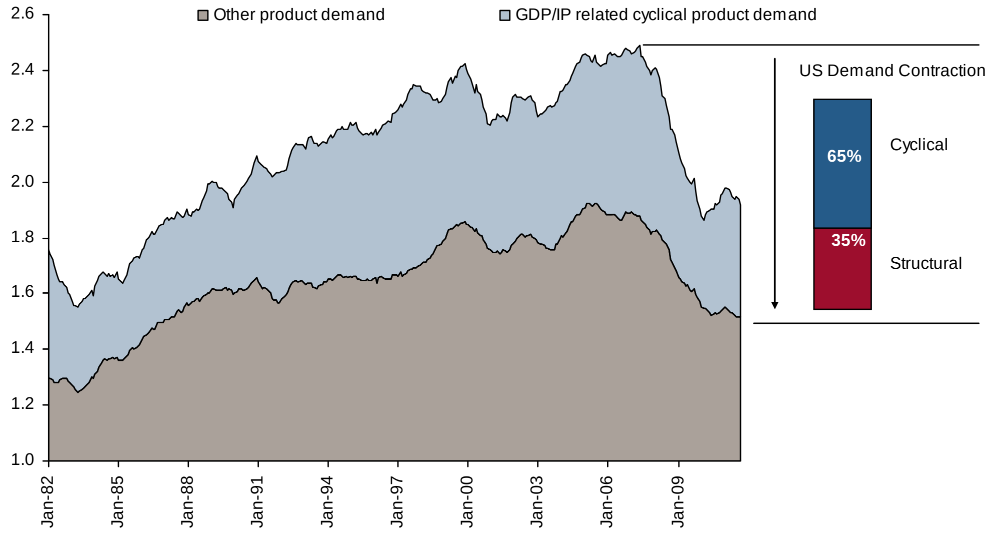
	Base	Bearish
Oil Demand in 2012	19.03 mb/d	19.19 mb/d
Assumption	2.10% ann. GDP growth	- 100 bp
Net diff. from Base	-	-200 kb/d
Yoy growth	-160 kb/d (-0.84%)	-360 kb/d (-1.88%)

Source: Credit Suisse Commodity Research.

SIDEBAR What's Cyclical vs. Structural?

A US Case Study

Exhibit 32: **US Structural and Cyclical Demand Contraction (Mb/d, 12-Month Moving Average)**



Source: Credit Suisse Global Commodities Research.

While US GDP is still set to grow in 2012, we see demand shrinking in all of our 2012 scenarios. the US is at a transition point where cyclical and structural downturns stop compounding at some point in 2012. Here's how we got to that crossroad.

Fortunately, the DoE has a long history of detailed, granular, monthly data on final use of "other oil products" including asphalt, lubricants, petroleum coke and other oils that are used throughout the "real" economy. This series tracks very well with IP. We call this the cyclical component of the "other products" category, which in its aggregate comprises between 12 and 15% of total oil consumption in the US or between 1.8 and 2.4 mb/d (about equal to all oil use in Germany in a good year).

The **less** cyclical (or structural) components of "other products" include natural gas liquids and other process fuels. *These oil products can be substituted out, mostly with natural gas. And much of that has happened by now.*

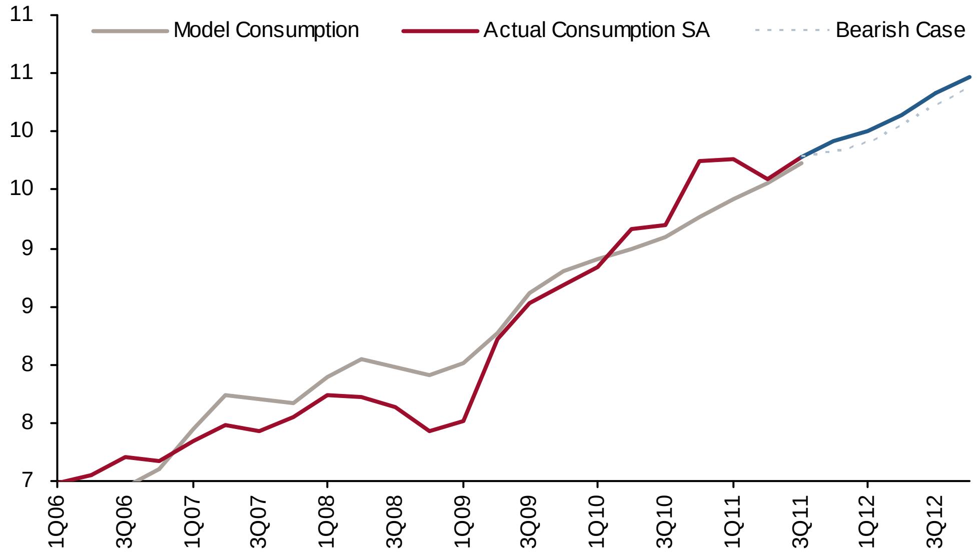
As shown above we see 65% of the roughly 650kb/d demand contraction that has taken place in the category of other products in the US since 2007 has been cyclical..

The structural component of decline has mostly to do with the steep decline in US natural gas prices from late 2008 onward. Cheap natural gas has also taken roughly 500kb/d of fuel oil use out of the oil consumption equation in the last 6 years. Last, in both the US and in parts of Europe (Germany, France and Italy), oil use in space heating and for power generation (Italy) has been falling significantly—a loss of demand of some 500-700kb/d in the last 10 years, judging from less granular data from the International Energy Agency. The only other contributor to "structural" declines in oil demand would be the combination of technology and efficiency gains in transport, which is more difficult to illustrate.

We estimate that about 1.5mb/d or a little more than one third of the ~4mb/d (-10%) contraction in aggregate OECD oil consumption involved "structural" declines

Separate and Distinct Scenarios by Region: China

Exhibit 33: China Oil Demand Scenarios



	Base	Bearish
Oil Demand in 2012	10.236mb/d	10.12 mb/d
Assumption	8.00% ann. GDP growth	- 100 bp
Net diff. from Base	-	-100 kb/d
Yoy growth	570 kb/d (5.79%)	460 kb/d (4.75%)

Source: Credit Suisse Global Commodities Research.

Base case for China: We expect Chinese real GDP to grow by 8% in 2012, which is 1% slower than the 9.0 rate of 2011. As for oil demand, we project growth of nearly 600kb/d, +6% next year, which is close to the historic norm of roughly 0.7 units of oil demand growth for each 1 unit of real GDP growth. This is also in line with the return to that norm oil intensity of GDP that we observed in the data for 2H2011, after a stretch of relatively high oil intensity that coincided with China's post global crisis monetary easing.

Bearish case for China: The bearish scenario for China involves a -100bps lower growth rate, which also fits with our complex global scenario involving a 'meltdown' in Europe and its spill-over effects.

In our model, 7% real China GDP growth in 2012 yields about 100 kb/d less oil demand growth than in the base case.

Sidebar: China as a Barometer for EM Oil Demand

… and Why Our Bear Case Is More Bearish Than It Looks

China is frequently used as shorthand for EM. In oil, this is less valid than in other commodity markets, but is still partially useful. We believe that the China bear case can be extended across much of the EM oil demand universe, excepting to a degree the rising tide of oil use in the Mideast. Key Mideast economies would still run budget surpluses in our $80Brent case, and/or would have the reserves to continue to expand and invest. What's more, they remain *oil*-economies with very few energy diversification options in the shorter term.

GDP and oil use remain more tightly entwined in China and most other EM economies than across the OECD. Moving economic performance down from a base case that is already rather muted by recent historical standards would be a big deal.

We don't think that even in a global bearish scenario, China would allow it's GDP to collapse below 7.5% real growth. Nor do we think that officials in other key economies are without means to stimulate growth if necessary. In line with our broader team, we believe that economic performance this year will be driven by policy, and think that even in the bearish case we won't see a synchronized global depression.

Additional Notes on Demand

Far and away most of the delta in oil demand will be cyclical in the short to medium term (next 3-5 years). And the lion's share of the delta involves the combination of diesel and jet fuel (middle distillates). In our base case, we'll probably keep significant tension on the global distillate s/d, with a relatively high baseline for that part of refining margins. The bear case would upset the margin and profit picture that has emerged in the last two years. Ironically in the bear-case, gasoline margins could perform, under the theory that collapsing middle distillate profits would leave little else for refiners to turn to.

The time for more structural demand changes driven by *greater efficiency gains and/or changing technology* is coming later this decade. Not much of that trend shift is visible now.

Exhibit 34: WTI and Brent Forecasts in Different Scenarios

Base case

Assumptions:

- Europe crisis is getting better
- US
- China
- Global Demand grows to 90.47 mb/d on average in 2012

Oil Forecasts (US$/b)	2010*	2011					2012					2013					2014	Long term
		Q1*	Q2*	Q3*	Q4*	Yr Avg.	Q1 (f)	Q2 (f)	Q3 (f)	Q4 (f)	Yr Avg (f)	Q1 (f)	Q2 (f)	Q3 (f)	Q4 (f)	Yr Avg (f)	Yr Avg (f)	(real)
Brent	**83.13**	101.27	116.99	112.09	109.54	**109.97**	100.00	100.00	110.00	110.00	**105.00**	105.00	115.00	120.00	120.00	**115.00**	**120.00**	**90.00**
WTI	**79.61**	94.60	102.34	89.54	92.18	**90.70**	90.00	92.00	106.00	108.00	**99.00**	103.00	113.00	118.00	118.00	**113.00**	**117.75**	**84.00**
WTI - Brent Spread	**-3.52**	-6.67	-14.65	-22.55	-17.36	**-19.27**	-10.00	-8.00	-4.00	-2.00	**-6.00**	-2.00	-2.00	-2.00	-2.00	**-2.00**	**-2.25**	**-6.00**

Bullish outcome

Assumptions:

- Europe recovers faster than expexted: OECD Europe grows by 1 standard deviation above base case (~0.5 mb/d) to 13.56 mb/d on average in 2012
- US +50 bp from base case: US demand grows to 19.81 mb/d (~100 kb/d above base case)
- China +50 bp from base case: China demand grows to 10.24 mb/d (~50 kb/d above base case)
- Global Demand grows to 90.91 mb/d on average in 2012 (~450 mb/d above our base case)

Oil Forecasts (US$/b)	2010*	2011					2012					2013					2014	Long term
		Q1*	Q2*	Q3*	Q4*	Yr Avg.	Q1 (f)	Q2 (f)	Q3 (f)	Q4 (f)	Yr Avg (f)	Q1 (f)	Q2 (f)	Q3 (f)	Q4 (f)	Yr Avg (f)	Yr Avg (f)	(real)
Brent	**83.13**	101.27	116.99	112.09	109.64	**110.00**	115.00	120.00	120.00	115.00	**117.50**	115.00	120.00	120.00	120.00	**118.75**	**120.00**	**90.00**
WTI	**79.61**	94.60	102.34	89.54	92.28	**90.73**	105.00	112.00	116.00	113.00	**111.50**	113.00	118.00	118.00	118.00	**116.75**	**117.75**	**84.00**
Same WTI diffs as in base	**-3.52**	-6.67	-14.65	-22.55	-17.36	**-19.27**	-10.00	-8.00	-4.00	-2.00	**-6.00**	-2.00	-2.00	-2.00	-2.00	**-2.00**	**-2.25**	**-6.00**

Bearish outcome

Assumptions:

- Europe Crisis Worsen: OECD Europe demand moves down 2 standard deviations (~1 mb/d)
- US -100 bp from base case: US demand falls to 19.81 mb/d (~200 kb/d below base case)
- China -100 bp from base case: China demand falls to 10.09 mb/d (~100 kb/d below base case)
- Global Demand falls to 89.11 mb/d on average in 2012 (~1.5 mb/d below our base case)

Oil Forecasts (US$/b)	2010*	2011					2012					2013					2014	Long term
		Q1*	Q2*	Q3*	Q4*	Yr Avg.	Q1 (f)	Q2 (f)	Q3 (f)	Q4 (f)	Yr Avg (f)	Q1 (f)	Q2 (f)	Q3 (f)	Q4 (f)	Yr Avg (f)	Yr Avg (f)	(real)
Brent	**83.13**	101.27	116.99	112.09	109.64	**110.00**	70.00	80.00	80.00	90.00	**80.00**	100.00	100.00	110.00	110.00	**115.00**	**115.00**	**90.00**
WTI	**79.61**	94.60	102.34	89.54	92.28	**90.73**	60.00	72.00	76.00	88.00	**74.00**	98.00	98.00	108.00	108.00	**113.00**	**112.75**	**84.00**
Same WTI diffs as in base	**-3.52**	-6.67	-14.65	-22.55	-17.36	**-19.27**	-10.00	-8.00	-4.00	-2.00	**-6.00**	-2.00	-2.00	-2.00	-2.00	**-2.00**	**-2.25**	**-6.00**

Source: Company data, Credit Suisse estimates.

Oil Supply : Watch Out for MENA, Saudi Policy, and Non-OPEC Performance

We see three buckets of downside volume risk on the supply side, which all pertain to both the short and long term.

MENA instability, Saudi Arabia policy and non-OPEC underperformance need close attention

Instability in North Africa and the Middle East (Mena).

There remains upside and downside around the growth trajectories of Libya and Iraq. On Libya we observe that large, widely touted, short term gains appear to be exaggerated and remain worried that they will not prove easily sustainable as the country literally builds elementary civil institutions from scratch in a fractured domestic and unstable regional environment. About Iraq, the departure of the last of the foreign uniformed military forces marks the beginning of a new chapter. Its oil supply is not likely to grow anymore predictably or smoothly than in the last 10-odd years. Indeed we depart from the consensus in expecting less growth pa through 2015 and seeing major downside risk even to that low base. We worry for the prospects of growth sanctioned by Baghdad, about rising IOC involvement in the Kurdish upstream, about the rising number and severity of reported sabotage in the south; the growing likelihood of foreign sponsored aggression adding to the already formidable and deep-rooted domestic discord (and its attendant violence); as well as the more ordinary bureaucratic and systemic headwinds to rapidly growing FDI into the upstream.

There is as yet no visibility around the return of optimum flows and investments of and into the oil and gas sectors of **Egypt**, **Yemen** and **Syria.** Nor is all stable and well across the upstream sectors of **Sudan**, **Chad,** and **Nigeria**.

There remains **disruption risk in Algeria,** which shares many of the key trends that played into the regime changes witnessed in Tunisia and Egypt and the grievances aired in Morocco.

As a sidebar, because it’s not part of the region, we mention **Venezuela.** We see interruption risk surrounding any sudden regime change. Catalysts could be President Chavez’ well-documented illness, or elections late in the year. It’s noteworthy too that there’ll be significant elections in 2012 in a number of other large producing countries as well, including Russia and the US.

Last but not least is the increasing diplomatic and political tension around **Iran**. We think the risk of a military conflict remains very, very small. But very real is the apparently accelerating drive toward sanctions on Iran’s oil exports (into Europe). That adds to already reportedly painful sanctions on Iran’s industrial sector (including the oil and gas upstream) and financial sector. Iran’s response to any of these moves is unpredictable. What’s clear is that further tightening will at the very least add to the cost of trading Iranian oil, and through the upsetting of established commercial relationships will add to the price of oil as well.

Changed Attitude and Oil Policy of Saudi Arabia

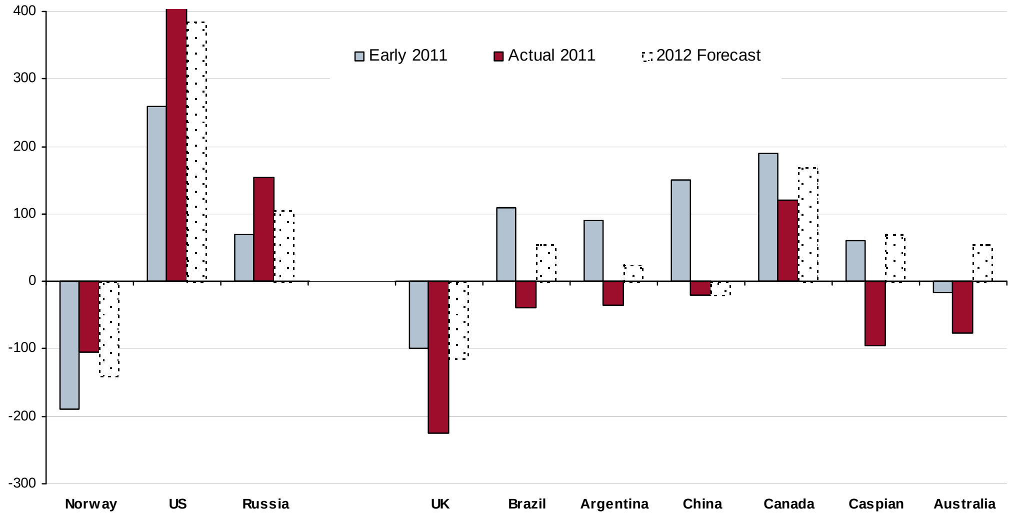
We believe that the kingdom can no longer blithely be counted upon to simply supply more and relatively cheap oil in the short or long term. We observe that as the de facto “swing producer,” Saudi Arabia allowed OECD inventories of crude oil to fall below 5-year averages despite (or because of?) high prices and a significant midyear release of strategic petroleum reserves in 2011. We also observe that the Kingdom cancelled plans for further expansion of its installed production capacity. And finally we note that Saudi policy in the region has become more assertive about its own national interest. It now loudly protests the need for stability and is not shy about enforcing that stability domestically or in neighbouring countries (e.g. Bahrain, Yemen). As such, it's at cross purposes with US foreign policy.

Non-OPEC Underperforming in 2011

Norway, the US, and Russia outperformed in 2011, but a larger list of non-OPEC producers underperformed

The list of *under*-performing producing countries is long. Causes include the transitory type—e.g., weather in the **US** and **Canada** in 1H11; and accidents, e.g., **China**. But causes also include a turning of the tide, e.g., moderate declines across **Mexico** slipping into steeper aggregates as upstream upside is tapped out; or simply slowing growth in **India**, **Oman** and **Ecuador**. Then there is an interim, *new normal* in **Brazil**, where output is flat-lining at best as the need for maintenance intensifies and declines accelerate across the established offshore fields, before the new crop of super-giants can get into its full development phase. As for maintenance, that's blamed for much lower than planned flows from **Azerbaijan** and **Kazakhstan** as well. We'd note, however, that off-setting developments are subject to more than their fair share of commercial and technical difficulties and could suffer still more if political stability begins to wobble more. Lastly, in the **UK offshore** a veritable *annus horribilis* appears to have played out.

Exhibit 35: Non-OPEC Under- and Overperformance by Country



Source: Credit Suisse Global Commodities Research.

The list of *over*-performers is short. Best in class is the stunning performance recorded in **Texas** through July. We should note for fairness as well that **Russia**'s upstream continues to grow. And that in **Colombia** too production continues to ramp higher at a steady clip.

Exhibit 36: Oil Demand Forecasts

Demand	2010	Q1-'11	Q2-'11	Q3-'11E	Q4-'11E	2011E	Q1-'12E	Q2-'12E	Q3-'12E	Q4-'12E	2012E	2013E	2014E
Global	88.8	89.4	88.7	90.2	91.2	89.9	90.7	90.2	91.7	92.8	91.4	93.1	94.4
YoY Growth, net mb/d	3.1	2.3	0.7	0.6	0.9	1.1	1.3	1.5	1.5	1.5	1.5	1.7	1.4
YoY Growth, %	3.6%	2.7%	0.8%	0.6%	1.0%	1.2%	1.5%	1.6%	1.7%	1.7%	1.6%	1.9%	1.5%
OECD	46.2	46.2	44.5	45.9	46.3	45.7	46.2	44.4	46.0	46.3	45.7	45.9	46.1
YoY Growth, net mb/d	0.6	0.3	-0.8	-0.8	-0.4	-0.4	-0.1	0.0	0.1	0.1	0.0	0.1	0.2
YoY Growth, %	1.2%	0.6%	-1.8%	-1.6%	-1.0%	-1.0%	-0.1%	-0.1%	0.2%	0.1%	0.0%	0.3%	0.5%
North America	23.8	23.7	23.2	23.5	23.6	23.5	23.4	23.1	23.5	23.6	23.4	23.4	23.6
YoY Growth, net mb/d	0.5	0.3	-0.5	-0.6	-0.3	-0.3	-0.2	-0.2	0.0	0.0	-0.1	0.0	0.2
YoY Growth, %	2.0%	1.2%	-2.0%	-2.4%	-1.1%	-1.1%	-1.0%	-0.7%	0.0%	0.0%	-0.4%	0.2%	0.7%
Europe	14.6	14.2	14.1	14.7	14.6	14.4	14.1	14.1	14.7	14.6	14.4	14.5	14.4
YoY Growth, net mb/d	-0.1	-0.1	-0.1	-0.2	-0.2	-0.2	0.0	0.0	0.0	0.0	0.0	0.1	-0.1
YoY Growth, %	-0.6%	-0.9%	-0.9%	-1.5%	-1.5%	-1.2%	-0.3%	-0.2%	-0.3%	-0.3%	-0.3%	0.7%	-0.4%
Asia Pacific	7.8	8.3	7.1	7.7	8.1	7.8	8.6	7.3	7.8	8.2	8.0	8.0	8.1
YoY Growth, net mb/d	0.2	0.1	-0.2	0.0	0.0	0.0	0.2	0.2	0.1	0.1	0.2	0.0	0.1
YoY Growth, %	2.4%	1.5%	-3.1%	0.6%	0.4%	-0.1%	2.7%	2.2%	1.7%	1.0%	1.9%	0.1%	1.3%
Non-OECD	42.6	43.2	44.3	44.3	44.9	44.2	44.6	45.7	45.8	46.4	45.6	47.2	48.3
YoY Growth, net mb/d	2.6	2.1	1.5	1.3	1.3	1.5	1.4	1.5	1.4	1.5	1.4	1.6	1.1
YoY Growth, %	6.5%	5.0%	3.5%	3.1%	3.0%	3.6%	3.2%	3.4%	3.2%	3.3%	3.3%	3.4%	2.4%
Former Soviet Union	4.5	4.6	4.5	4.9	4.8	4.7	4.7	4.6	5.0	4.9	4.8	4.9	5.1
YoY Growth, net mb/d	0.3	0.4	0.3	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
YoY Growth, %	7.0%	8.3%	7.7%	3.0%	2.0%	5.1%	2.1%	2.2%	2.6%	2.3%	2.3%	2.6%	2.7%
China	9.2	9.6	9.8	9.7	10.0	9.8	9.9	10.3	10.2	10.5	10.2	10.7	11.0
YoY Growth, net mb/d	1.0	0.9	0.4	0.6	0.3	0.6	0.3	0.5	0.5	0.5	0.4	0.5	0.4
YoY Growth, %	12.1%	10.6%	4.5%	6.3%	3.4%	6.1%	2.8%	4.6%	4.9%	4.9%	4.3%	4.6%	3.3%
Other emerging Asia	10.9	11.2	11.6	10.9	11.5	11.3	11.7	12.0	11.1	11.8	11.7	12.0	12.3
YoY Growth, net mb/d	0.4	0.3	0.4	0.3	0.4	0.3	0.5	0.4	0.3	0.3	0.4	0.4	0.3
YoY Growth, %	3.4%	2.4%	3.8%	2.9%	3.4%	3.1%	4.3%	3.4%	2.5%	3.0%	3.3%	3.1%	2.1%
South America	6.4	6.3	6.6	6.8	6.8	6.6	6.5	6.7	7.0	7.0	6.8	7.0	7.1
YoY Growth, net mb/d	0.3	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
YoY Growth, %	5.7%	3.9%	2.6%	2.0%	3.4%	3.0%	2.6%	2.5%	2.7%	2.7%	2.6%	3.0%	1.1%
Mideast	7.4	7.2	7.6	7.9	7.5	7.6	7.3	7.8	8.1	7.7	7.8	8.0	8.3
YoY Growth, net mb/d	0.4	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
YoY Growth, %	5.4%	3.2%	2.5%	1.3%	2.7%	2.4%	2.5%	2.7%	2.7%	2.7%	2.6%	2.8%	3.5%
Africa	3.4	3.5	3.4	3.4	3.6	3.5	3.6	3.6	3.6	3.8	3.6	3.8	3.8
YoY Growth, net mb/d	0.2	0.0	0.0	0.1	0.1	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.0
YoY Growth, %	5.4%	1.3%	-1.3%	2.1%	2.6%	1.2%	4.7%	4.8%	4.7%	4.6%	4.7%	4.8%	1.2%

Source: Company data, Credit Suisse estimates.

Exhibit 37: **Oil Supply Forecasts**

Supply	2010	Q1-'11	Q2-'11	Q3-'11E	Q4-'11E	2011E	Q1-'12E	Q2-'12E	Q3-'12E	Q4-'12E	2012E	2013E	2014E
Global	88.3	89.3	88.8	89.2	90.4	89.4	90.4	90.8	91.3	92.2	91.2	93.4	94.8
YoY Growth, net mb/d	2.5	1.8	0.8	0.5	1.2	1.1	1.1	2.0	2.1	1.9	1.8	2.2	1.4
YoY Growth, %	2.9%	2.1%	0.9%	0.6%	1.4%	1.2%	1.2%	2.2%	2.3%	2.1%	2.0%	2.4%	1.5%
Non OPEC	50.5	51.0	50.4	50.3	51.1	50.7	51.2	51.2	51.3	52.2	51.5	52.6	53.3
YoY Growth, net mb/d	1.1	0.6	0.2	0.0	0.0	0.2	0.2	0.8	1.1	1.1	0.8	1.1	0.6
YoY Growth, %	2.3%	1.3%	0.3%	0.1%	0.0%	0.4%	0.4%	1.5%	2.1%	2.2%	1.6%	2.2%	1.2%
North America	15.0	15.3	15.2	15.3	15.8	15.4	15.7	15.6	15.8	16.2	15.8	16.3	16.5
YoY Growth, net mb/d	0.6	0.4	0.4	0.3	0.5	0.4	0.3	0.3	0.5	0.4	0.4	0.5	0.3
YoY Growth, %	4.3%	3.0%	3.0%	2.1%	3.6%	2.9%	2.2%	2.0%	3.0%	2.4%	2.4%	3.0%	1.7%
South America	4.5	4.6	4.5	4.6	4.6	4.6	4.7	4.7	4.7	4.8	4.7	5.0	5.2
YoY Growth, net mb/d	0.2	0.2	-0.1	0.0	0.1	0.0	0.2	0.2	0.2	0.1	0.2	0.3	0.2
YoY Growth, %	4.8%	3.8%	-1.1%	0.3%	1.4%	1.1%	3.4%	5.0%	3.7%	3.0%	3.8%	5.8%	4.0%
Europe	4.5	4.6	4.6	4.2	4.5	4.5	4.4	4.1	3.9	4.2	4.1	4.0	3.8
YoY Growth, net mb/d	-0.3	-0.3	0.1	0.0	-0.1	-0.1	-0.2	-0.5	-0.2	-0.3	-0.3	-0.2	-0.2
YoY Growth, %	-6.7%	-5.6%	1.2%	0.1%	-3.2%	-2.0%	-5.1%	-10.1%	-6.0%	-6.3%	-6.9%	-4.0%	-4.3%
FSU	13.6	13.7	13.7	13.7	13.6	13.7	13.7	13.8	13.8	14.0	13.8	14.1	14.3
YoY Growth, net mb/d	0.3	0.2	0.1	0.1	-0.1	0.1	0.0	0.2	0.2	0.5	0.2	0.3	0.2
YoY Growth, %	1.9%	1.5%	0.5%	0.6%	-0.7%	0.5%	-0.3%	1.2%	1.2%	3.3%	1.4%	2.0%	1.5%
Russia	10.5	10.6	10.6	10.7	10.7	10.7	10.6	10.7	10.8	10.9	10.7	10.9	10.9
YoY Growth, net mb/d	0.2	0.2	0.1	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.2	0.0
YoY Growth, %	2.4%	1.5%	1.3%	1.8%	1.1%	1.4%	0.3%	0.8%	0.8%	1.3%	0.8%	1.4%	-0.2%
Africa	2.7	2.7	2.6	2.7	2.7	2.7	2.7	2.8	2.9	2.9	2.8	3.1	3.1
YoY Growth, net mb/d	0.0	0.0	-0.1	0.0	0.0	0.0	0.1	0.3	0.2	0.2	0.2	0.2	0.1
YoY Growth, %	0.9%	1.9%	-3.7%	0.3%	1.0%	-0.1%	2.5%	10.1%	7.1%	7.8%	6.9%	7.9%	2.6%
Mideast	1.7	1.7	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.6
YoY Growth, net mb/d	0.0	0.0	-0.1	-0.1	-0.1	-0.1	-0.1	0.1	0.0	0.1	0.0	0.0	-0.1
YoY Growth, %	1.4%	-0.1%	-6.9%	-5.7%	-7.5%	-5.1%	-3.4%	4.1%	2.4%	3.6%	1.6%	-1.1%	-3.0%
Asia	8.5	8.4	8.3	8.2	8.3	8.3	8.4	8.5	8.5	8.5	8.5	8.5	8.6
YoY Growth, net mb/d	0.3	0.1	-0.1	-0.3	-0.3	-0.2	0.0	0.2	0.3	0.2	0.2	0.1	0.1
YoY Growth, %	4.0%	0.6%	-1.7%	-3.4%	-3.0%	-1.9%	-0.4%	2.7%	3.4%	2.2%	2.0%	0.8%	1.1%
Processing gain	2.7	2.7	2.7	2.9	2.9	2.8	2.8	2.8	3.0	3.0	2.9	3.0	3.0
OPEC	35.2	35.6	35.7	36.0	36.4	35.9	36.4	36.8	36.9	37.1	36.8	37.8	38.5
YoY Growth, net mb/d	1.3	1.1	0.5	0.4	1.1	0.8	0.8	1.1	0.9	0.6	0.8	1.0	0.7
YoY Growth, %	3.8%	3.1%	1.5%	1.0%	3.0%	2.1%	2.2%	3.0%	2.5%	1.7%	2.4%	2.7%	2.0%
Opec Crude Oil	29.9	30.3	30.2	30.5	30.7	30.4	30.7	31.0	31.2	31.2	31.0	32.0	32.7
YoY Growth, net mb/d	0.7	0.8	0.2	0.2	0.7	0.5	0.4	0.8	0.7	0.5	0.6	1.0	0.7
YoY Growth, %	2.5%	2.9%	0.8%	0.6%	2.4%	1.7%	1.4%	2.6%	2.2%	1.6%	1.9%	3.2%	2.1%
Opec 11	27.5	27.5	27.3	27.7	27.9	27.6	27.8	28.0	28.2	28.2	28.0	28.8	28.9
YoY Growth, net mb/d	0.7	0.6	-0.2	-0.3	0.4	0.1	0.3	0.7	0.5	0.2	0.4	0.7	0.2
YoY Growth, %	2.6%	2.2%	-0.7%	-0.9%	1.5%	0.5%	1.0%	2.6%	1.8%	0.9%	1.5%	2.7%	0.5%
Opec non-crude	5.3	5.3	5.5	5.6	5.7	5.5	5.7	5.8	5.8	5.8	5.8	5.8	5.8
YoY Growth, net mb/d	0.5	0.2	0.3	0.2	0.3	0.3	0.4	0.3	0.2	0.2	0.3	0.0	0.1
YoY Growth, %	11.6%	4.3%	5.4%	3.4%	6.4%	4.9%	7.0%	5.6%	3.8%	2.6%	4.7%	0.1%	1.2%

Source: Company data, Credit Suisse estimates.

Exhibit 38: **Oil Supply and Demand Balances**

Balance, stocks	2010	Q1-'11	Q2-'11	Q3-'11E	Q4-'11E	2011E	Q1-'12E	Q2-'12E	Q3-'12E	Q4-'12E	2012E	2013E	2014E
Implied inventory change	-0.4	-0.1	0.1	-1.0	-0.9	-0.5	-0.3	0.6	-0.4	-0.5	-0.2	0.3	0.4
Reported oil inventory:													
OECD stock change	0.0	-0.3	0.5	-0.2	-0.8	-0.2	-0.2	0.3	-0.3	-0.5	-0.5	0.1	0.2
OECD inventory (billion barrels)	2.65	2.63	2.67	2.66	2.58	2.58	2.57	2.59	2.56	2.52	2.52	2.54	2.60
Cover, days demand	57.3	59.1	58.3	57.4	56.0	56.0	57.7	56.4	55.3	54.4	54.4	55.5	0.0
'Call on Opec & stocks"	30.4	30.4	30.1	31.4	31.6	30.9	31.0	30.4	31.6	31.8	31.2	31.7	32.3
YoY Growth, net mb/d	1.3	1.3	0.1	0.2	0.4	0.5	0.6	0.3	0.1	0.1	0.3	0.5	0.6
YoY Growth, %	4.6%	4.6%	0.4%	0.7%	1.2%	1.7%	2.1%	0.9%	0.4%	0.4%	0.9%	1.6%	1.8%

Source: Company data, Credit Suisse estimates.

US Natural Gas in 2012

2011 proved to be yet another banner year for US natural gas production. Productivity gains and technological advancements have lead to a surge in production growth. Dry gas production has averaged an impressive 61.3 Bcf/d in 2011 according to most recent pipeline flows, good for a +4.2 Bcf/d y-o-y gain, yet gas rig counts have remained under year ago levels (Exhibit 39and Exhibit 40). We expect growth in US natural gas production to yet again overwhelm the market in 2012, leaving end of March and October storage levels at historical highs but prices at historical lows.

We expect growth in US natural gas production to yet again overwhelm the market in 2012

However, we are now characterizing 2013 as a transition year when balances and storage levels begin to move back into normal ranges, followed by improvements in natural gas prices. Further along the curve, we hold our favorable view for US gas demand through a number of policy initiatives as well as prospects for LNG exports from the US and Canada.

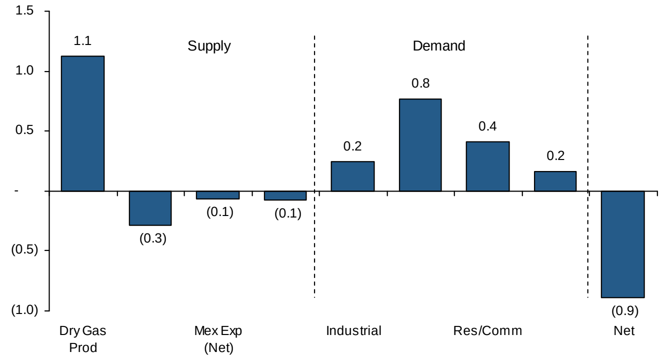
Exhibit 39: Credit Suisse US Natural Gas Balance

(Bcf/d)

(Bcfd)	2010	2011E	2012E	2013E	2014E	LT (real)
Dry Gas Production	59.1	62.8	63.9	62.3	64.0	
Canadian Imports (Net)	7.0	6.0	5.7	6.3	6.0	
Mexican Exports (Net)	(0.8)	(1.3)	(1.4)	(1.6)	(1.8)	
LNG Imports (Net)	1.2	0.7	0.7	0.6	0.5	
Total Supply	**66.4**	**68.2**	**68.9**	**67.6**	**68.8**	
Industrial	18.1	18.4	18.7	19.1	19.2	
Power	20.2	20.7	21.5	22.3	23.0	
Res/Comm	22.4	22.1	22.5	22.5	22.3	
Other	5.4	5.6	5.7	5.9	5.9	
Total Demand	**66.0**	**66.8**	**68.4**	**69.8**	**70.5**	
End of Mar Storage (Bcf)	1,638	1,618	2,173	1,758	1,706	
End of Oct Storage (Bcf)	3,821	3,794	4,042	3,608	3,530	
Price Forecast ($/Mmbtu)	**$4.32**	**$ 4.07**	**$ 3.50**	**$ 4.70**	**$ 5.10**	**$ 5.50**
Previous Forecast ($/Mmbtu)	**$4.32**	**$ 4.20**	**$ 4.40**	**$ 4.90**	**$ 5.50**	**$ 5.50**

Source: Credit Suisse.

Exhibit 40: Key Components 2012 vs. 2011



Source: Credit Suisse.

Short-Term Pain

As stated in our note, *Marking-to market 4Q2011, adjusting US gas and WTI* , due in large part to the growth in onshore shale gas production in 2011 as well as a lack of heating demand, an unusually severe collision of bearish factors is expected to progress in 2012. So far, there is still no sign of the high-latitude blocking that is typically associated with extended winter cold. Indeed, with a third of December now gone and the remaining two-thirds recently being revised warmer, particularly in the Northeast region, it looks as though we will enter January with historical records in storage near 3.4 Tcf. Though January and February do have preliminary forecasts for near 30-year normal weather, heating demand is expected to end the winter season not adding up to anything near 2011 heating demand, leaving stocks in excess over years previous.

2012 prices to average $3.50 per Mmbtu

Additionally, mandatory seasonal storage cycling and a hefty backlog of uncompleted wells could bring a wave of unwanted gas to market in 1H2012.

We estimate that approximately 40% or 1.62 Tcf of working gas capacity is under strict withdrawal programs or *ratchets* that are designed to extract most or a percentage of its working gas capacity by the end of March. What's more, by our estimates, approximately 1,800 wells remain drilled but uncompleted across the various basins in the lower-48. As a 5% well backlog is normal for the industry, we don't expect all wells to be completed and brought to market. However, if just half of these wells are completed, we could see an additional 1.8-3.6 Bcf/d added to 2012 production.

Coal switching may be the only near-term support, but it may come with a cost.

$2.95 per Mmbtu to switch on PRB CCGT plants

Economic dispatch models for combined-cycle (CCGT) plants show that almost all facilities except those plants burning PRB coal would have switched at the current price level. According to an SNL Energy report released in this summer, the gas floor for Central and Northern Appalachian coal would switch above $5 per Mmbtu, while Illinois Basin and Rockies coal switched at $3.80 and $3.74 per Mmbtu respectively. As current switching has yet to substantially balance the market based on storage levels, reaching the final threshold of coal switching would require a $2.95 per Mmbtu natural gas price to switch Powder River Basin CCGT plants. If prices do fall to the next level of coal switching, upstream activity will likely be compromised.

Just How Bad for How Long?

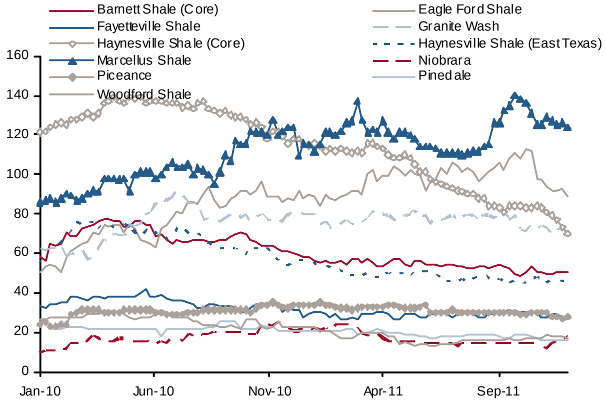
The good news is that a quicker transition toward a more "disciplined" upstream sector may come from the lower prices that we project in 2012. We note that in our forecasted scenario for $3.50 per Mmbtu average prices in 2012, Haynesville (Core) becomes increasingly uneconomic while NE Marcellus is pushed on the margin.

Producers are confirming sour economics.

Following Q3 earnings, we noted a few Haynesville, Marcellus, and Barnett Shale producers holding CAPEX flat to 2011 while others noted reductions in rig counts in those key producing regions[1]. However, we find recent rig counts allusive and slightly exaggerated as the amount NGL driven drilling in the US is causing true full cycle costs to not fully reflect trends in future production. True, the recent 95 rig (10%) correction in rigs since mid October is noteworthy, but we think the total gas rig count may need to fall below 750 to drive natural gas production lower. In our view, further falls in Haynesville and Barnett shale are needed as are overall declines in the dry gas regions of the Eagle Ford and the Marcellus. If these declines don't materialize, the market will likely hold near current price levels through 2012 and into 2013, likely creating a much more bearish scenario than what we have forecasted.

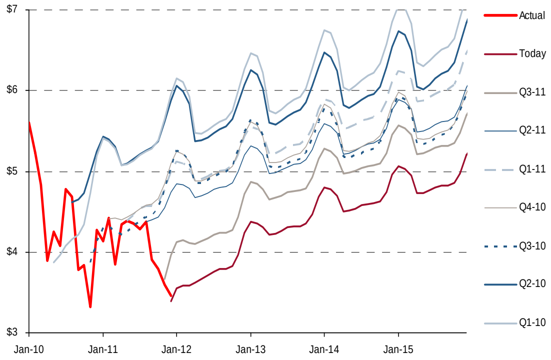
Low prices should pressure rig counts; however the rig count may need to fall below 750 to drive natural gas production lower

Exhibit 41: Total Gas Rig Counts in Key Producing Regions



Source: Smith Bit STATS, Credit Suisse.

Exhibit 42: Falling Forward Curve Impedes 2012-13 Hedging Activity



Source: the BLOOMBERG PROFESSIONAL™ service, Credit Suisse.

---

[1] Exco (Haynesville and Marcellus producer) announced reductions to capital budget for 2012 and reduction of Haynesville rig count from 22 to 13 while its Marcellus count increases to 5 in 2012. Ultra will keep spending flat in 2012 shift capital from ROX to Marcellus and reducing Pinedale rigs from 8 to 4

Lighter hedging by gas producers may accelerate production rationalization.

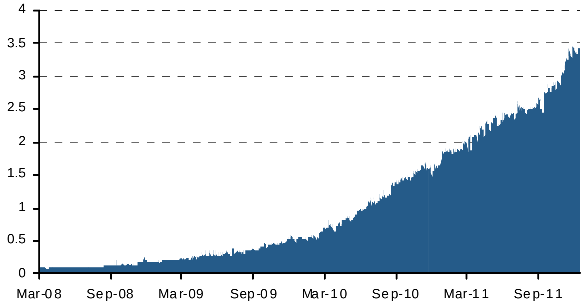
In our view (and based on producer hedging statistics), this year's falling futures curve has made it increasingly difficult for producers to lock in profitable hedges (Exhibit 42), which should help reduce activity in a more timely matter. We note that with the entire forward curve through 2015 at sub-$5, the number of economic dry gas basins is quickly diminishing. Industry reports have producers much less hedged for 2012 than they were in previous years (50% less than at this time last year) inevitably increasing their exposure to depressed spot prices. Of course, we can also make the case that current prices of NGLs are subsidizing gas production in many other basins, further complicating matters.

Marcellus growth is constrained only by pipeline expansions.

Liquids-rich plays: let the good times roll

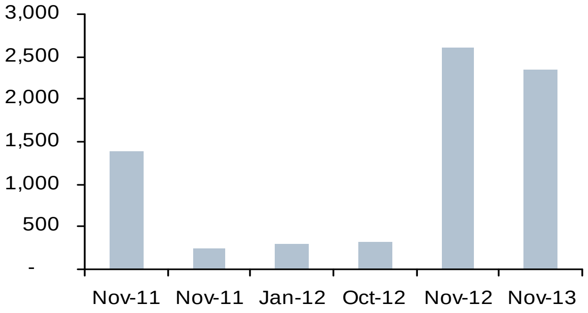
One region expected to contribute to the overall production growth trajectory in 2012 is the Marcellus shale. Responding to promising economics and liquids rich volumes, the Marcellus shale is approaching 3.5 Bcf/d in daily gas production, a 1.8 Bcf/d increase from last year (Exhibit 43). In fact, as this play matures even further, we see the only impediment of growth is the need for additional take-away capacity to key markets further east. With a slew of expansion and new pipeline projects coming online in 2012 (~3 Bcf/d by year end) we expect production growth to follow these projects as they come in-service (Exhibit 44) . National fuel, Dominion, Tetco, El Paso all have projects coming inline during 4Q of 2012 and should help alleviate some of the current bottlenecks still plaguing the play today. Interestingly, growth in the Marcellus alone could keep US production elevated in 2012 and extend the current bust cycle.

Exhibit 43: Daily Marcellus Gas Production



Source: Energy Velocity, Credit Suisse.

Exhibit 44: Marcellus Pipeline Expansions



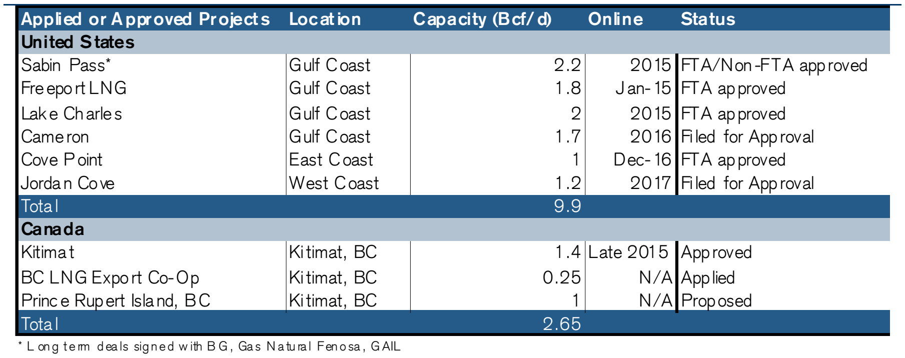
Source: Company data, Credit Suisse estimates.

LNG Exports, Policy-Driven Demand Supporting Back-End Prices

Headway made for US LNG exports in 2011, but long road remains.

In addition to being granted DOE export approval to both free-trade and non-free trade nations, Cheniere Energy's Sabine Pass liquefaction project has locked in three long-term deals with LNG supply linked to Henry Hub prices. With only 2.2 Bcf/d out of a total ~10 Bcf/d approved thus far, we expect the remaining projects to come under increasing political scrutiny. With numerous policymakers currently studying the impact LNG exports may have on future domestic pricing, we think exporting close to 15% of the total gas consumed in 2010 will likely have material impacts on regional fundamentals and shouldn't be ignored. Therefore, we have a *cautiously optimistic* outlook for additional LNG supply projects and expect these projects to be under heightened oversight in obtaining full export approval.

Exhibit 45: **US Liquefaction Projects**



Applied or Approved Projects	Location	Capacity (Bcf/d)	Online	Status
United States				
Sabin Pass*	Gulf Coast	2.2	2015	FTA/Non-FTA approved
Freeport LNG	Gulf Coast	1.8	Jan-15	FTA approved
Lake Charles	Gulf Coast	2	2015	FTA approved
Cameron	Gulf Coast	1.7	2016	Filed for Approval
Cove Point	East Coast	1	Dec-16	FTA approved
Jordan Cove	West Coast	1.2	2017	Filed for Approval
Total		9.9		
Canada				
Kitimat	Kitimat, BC	1.4	Late 2015	Approved
BC LNG Export Co-Op	Kitimat, BC	0.25	N/A	Applied
Prince Rupert Island, BC	Kitimat, BC	1	N/A	Proposed
Total		2.65		

* Long term deals signed with BG, Gas Natural Fenosa, GAIL

Source: FERC, Platts, Credit Suisse.

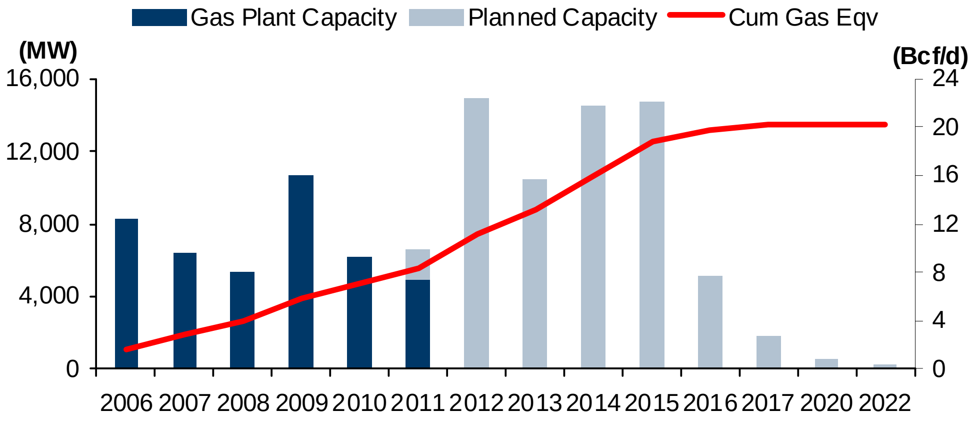
Interestingly, just around the time the first LNG export could theoretically leave US ports, the global LNG market should begin its transition to a looser situation (see our *Global Gas - From tight to loose by 2016E* report) as additional trains from Australia become in-service. Additionally, by 2016 we expect US power markets to be fully compliant with Cross-State Air Pollution Rules (CSAPR) as well as the recently finalized Mercury and Air Toxics standards (MATS). As these programs leave approximately 60 GW of US coal capacity at risk of closure by 2017, we forecast that will bring close to 5 Bcf/d of additional gas-fired power demand.

Longer term picture supported by LNG exports/demand prospects; however, even this demand growth could be overwhelmed by productivity improvements, which we discuss in the next section

Luckily, the gas power industry is well positioned to meet incremental demand.

Based on industry filings for additions in gas plant capacity, we estimate that while approximately 31 GW of coal retirements have been announced to date, 41 GW of gas fired plants have been added since 2006 and there appears to be an additional 64 GW planned to come in-service by 2022. Put another way, by 2022 gas plant capacity in the US looks prepared to increase by an additional 12 Bcf/d from today's levels. We think that not only are utilities recognizing that an industry transition is imminent but they are reacting to increasingly favorable economics for gas versus coal. We see domestic demand as likely the greatest factor in predicting a turnaround in prices for US based natural gas, and discuss this in more detail in our power market section.

Exhibit 46: **In-Service and Planned US Gas Plant Capacity with Gas Equivalent**



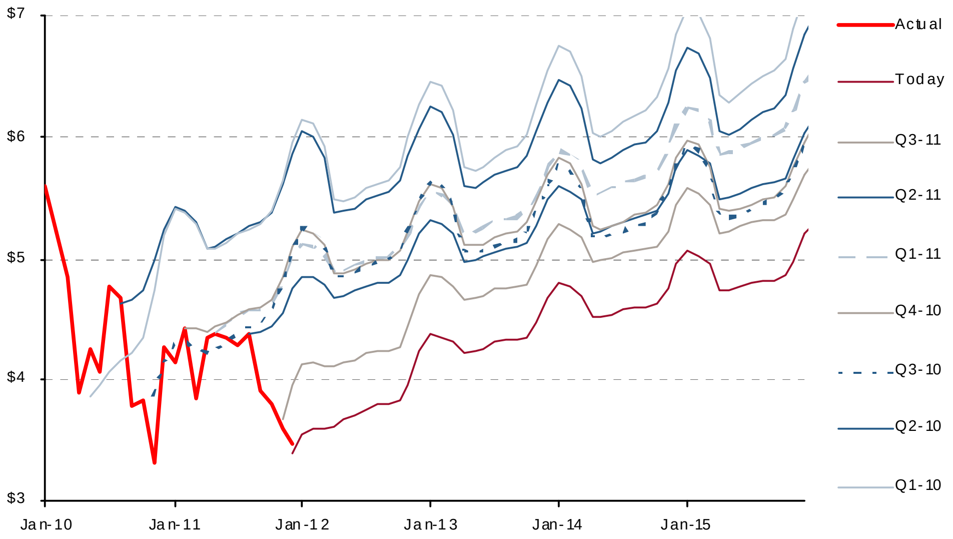
Source: Credit Suisse.

Focus on US Shale Gas Supply Potential

Transition Year for Natural Gas

Outside of weather, one of the most effective cures for a weak natural gas market has been low prices. Weak prices not only reduce the incentive for E&Ps to drill for gas, but also stimulate demand by encouraging fuel switching by electric utilities and other industrial users. Natural gas prices have tumbled sharply over recent quarters (see Exhibit 47) driving meaningful declines in gas directed activity

Exhibit 47: Falling Natural Gas Futures Curve



Source: Company data, Credit Suisse estimates.

While declines in gas drilling activity should be a precursor to moderating production trends, our supply-demand work suggests the gas market will still be more than 1 bcf/d oversupplied in 2012. We believe the prospects for a quick reset in the natural gas market is highly unlikely in 2012 given the following factors:

- *Shale plays entering the 'efficiency zone':* Widespread efficiency gains should blunt the impact from reduced dry gas drilling activity.
- *Surging Marcellus activity:* Significant increases in Marcellus production are likely in 2012 given the completion of several midstream projects, which will boost take-away capacity.
- *Majors getting ready to increase activity:* A meaningful activity ramp by Major and Foreign Oils is likely following $129 billion in shale related investments between 2008 and 2011. Anecdotal evidence from public land drillers indicate that Majors have increased their market share of announced land rig newbuilds to approximately 30%.
- *Bloated inventories are the 'elephant in the living room':* Natural gas inventories are on track to end the heating season above 2.0 Tcf, which should keep a lid on gas prices in 2012. We believe even Marcellus producers could be at risk of shut-ins given the bloated inventory picture.

That said, we view 2012 as a transition year to a gradually improved market in 2013 led by demand improvement and a stable supply picture.

Natural Gas Supply-Demand Model

Exhibit 48 illustrates Credit Suisse's natural gas supply-demand model. As a result of a sharp increase (+3.7 bcf/d) in YoY production, the gas market loosened considerably in 2011 despite continued improvements in overall demand (+0.8 bcf/d) as well as declines in net imports/exports (-1.9 bcf/d). We expect gas prices to remain range-bound until 2014, when we anticipate for more meaningful increases in gas fired generating capacity as utilities look to take advantage of low cost gas.

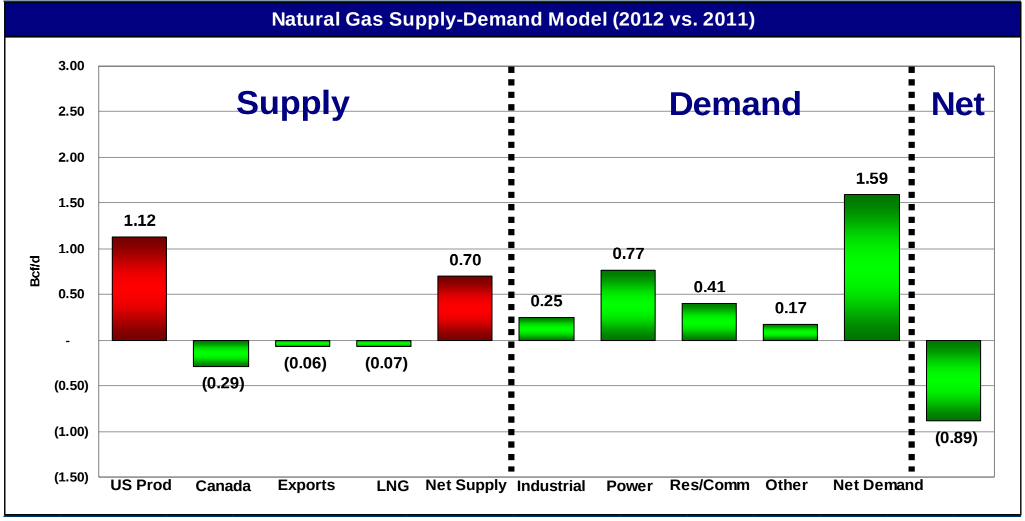
Exhibit 48: **Credit Suisse Natural Gas Supply-Demand Model**

(Bcfd)	2010	2011E	2012E	2013E	2014E	LT (Real)
Dry Gas Production	**59.1**	**62.8**	**63.9**	**62.3**	**64.0**	
Y-o-Y	2.7	3.7	1.1	(1.6)	1.7	
Canadian Imports (Net)	**7.0**	**6.0**	**5.7**	**6.3**	**6.0**	
Y-o-Y	(0.1)	(0.9)	(0.3)	0.5	(0.3)	
Mexican Exports (Net)	**(0.8)**	**(1.3)**	**(1.4)**	**(1.6)**	**(1.8)**	
Y-o-Y	0.0	(0.5)	(0.1)	(0.2)	(0.2)	
LNG Imports (Net)	**1.2**	**0.7**	**0.7**	**0.6**	**0.5**	
Y-o-Y	(0.1)	(0.4)	(0.1)	(0.1)	(0.1)	
Total Supply	**66.4**	**68.2**	**68.9**	**67.6**	**68.8**	
Y-o-Y	2.6	1.8	0.7	-1.3	1.2	
Industrial	**18.1**	**18.4**	**18.7**	**19.1**	**19.2**	
Y-o-Y	1.2	0.4	0.2	0.4	0.1	
Power	**20.2**	**20.7**	**21.5**	**22.3**	**23.0**	
Y-o-Y	1.4	0.5	0.8	0.8	0.8	
Y-o-Y Growth From Coal ret.			-	0.3	0.5	
Res/Comm	**22.4**	**22.1**	**22.5**	**22.5**	**22.3**	
Y-o-Y	0.7	(0.3)	0.4	0.0	(0.2)	
Other	**5.4**	**5.6**	**5.7**	**5.9**	**5.9**	
Y-o-Y	0.3	0.2	0.2	0.2	(0.0)	
Total Demand	**66.0**	**66.8**	**68.4**	**69.8**	**70.5**	
Y-o-Y	3.5	0.8	1.6	1.3	0.7	
Price Forecast ($/Mmbtu)	**$4.38**	**$ 4.07**	**$ 3.50**	**$ 4.70**	**$ 5.10**	**$ 5.50**
Previous Forecast ($/Mmbtu)		**$ 4.20**	**$ 4.40**	**$ 4.90**	**$ 5.50**	**$ 5.50**

Source: Company data, Credit Suisse estimates.

While we are bullish on longer-term demand trends, we still expect for a soft market in 2012, with the gas market approximately 0.5 bcf/d oversupplied, although the supply-demand balance should be 0.9 bcf/d tighter than in 2011 (Exhibit 49).

Exhibit 49: **Natural Gas Supply-Demand Dynamics: 2012 vs. 2011**



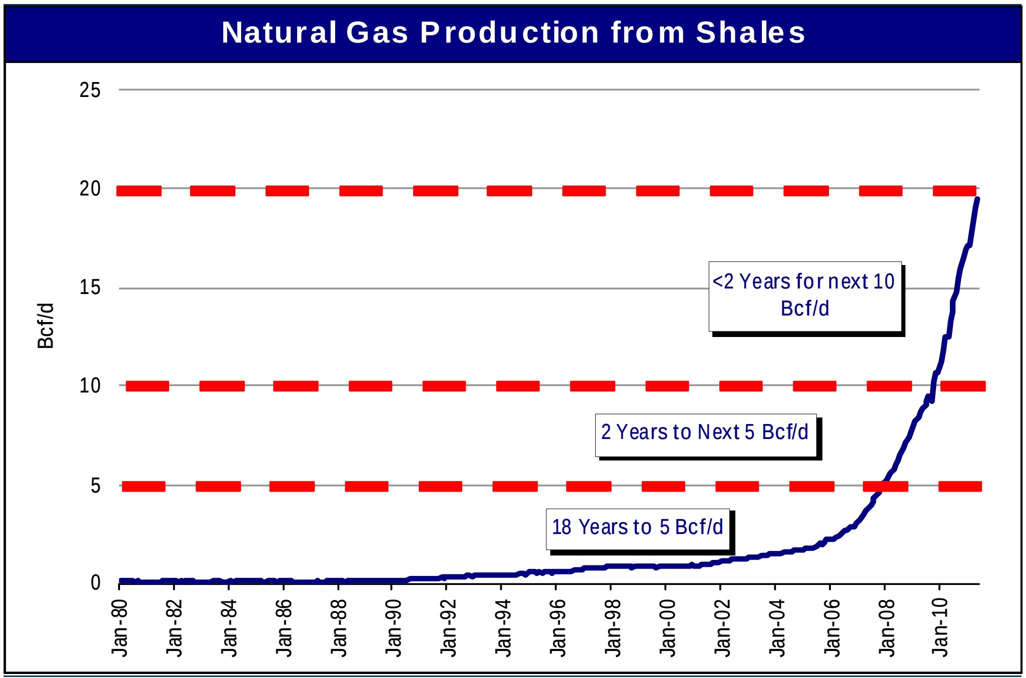
Source: Company data, Credit Suisse estimates.

Efficiency Gains Likely to Offset Further Declines in Activity

Shale efficiency gains allow for faster supply growth

The significant increase in natural gas supply has been driven by the remarkable increase in shale development, with US natural gas production from shales poised to exceed 20 bcf/d by early 2012 (Exhibit 50). It took the industry approximately 18 years to reach 5 bcf/d in production, but advances in horizontal drilling and completion technology have sharply compressed the cycle time. In fact, the industry is on track to grow natural gas supplies from shales by 10 bcf/d in less than 2 years.

Exhibit 50: **US Gas Production from Shales**

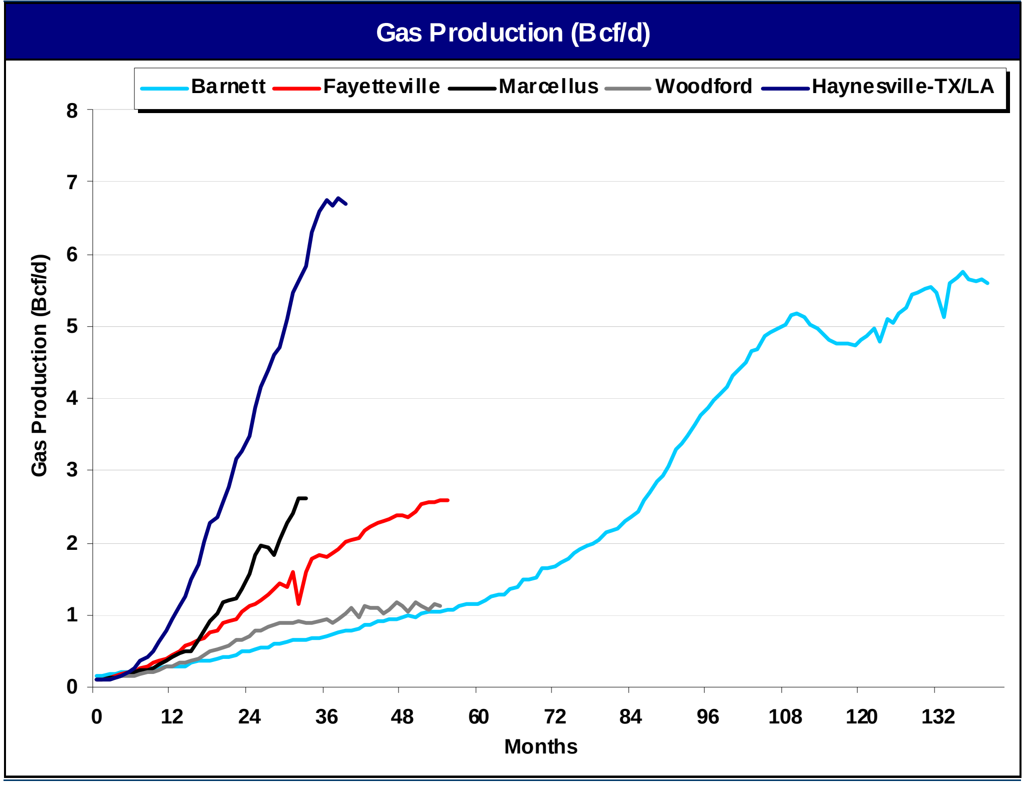


Source: HPDI, Credit Suisse estimates.

Exhibit 51 illustrates production trends from 5 of the industry's most prolific natural gas shale plays—The Barnett Shale, Fayetteville, Marcellus, Woodford, and Haynesville—on the same time scale. Note the dramatic steepening of production from the more recently discovered plays relative to the Barnett.

Exhibit 51: **Natural Gas Production from Big 5 Shale Plays**

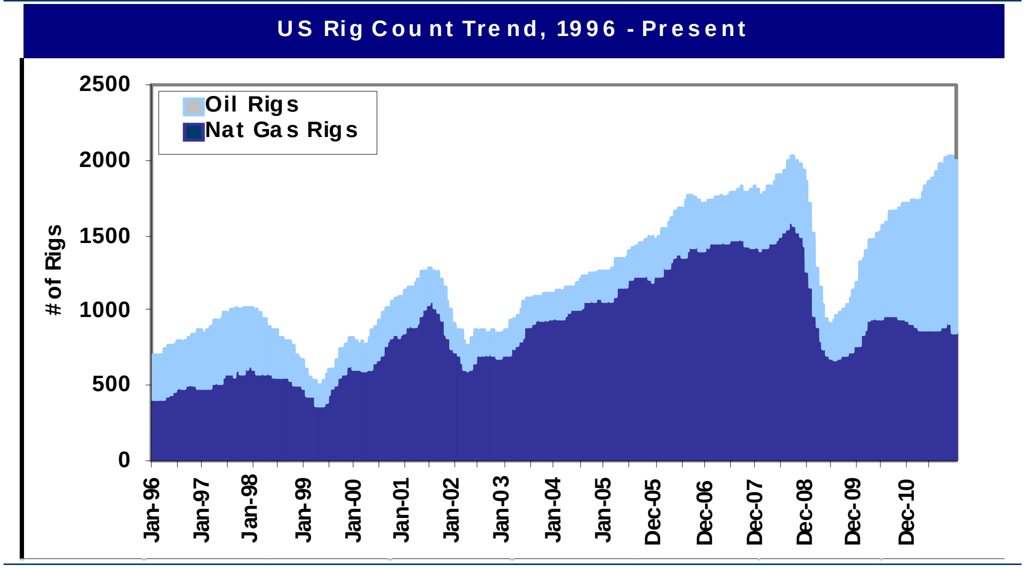
Learning curve for new plays is steeper than older plays



Source: Company data, Credit Suisse estimates.

Despite meaningful drop in natural gas directed rig activity, natural gas production trends continue to rise at a sharp pace, which has surprised the market.

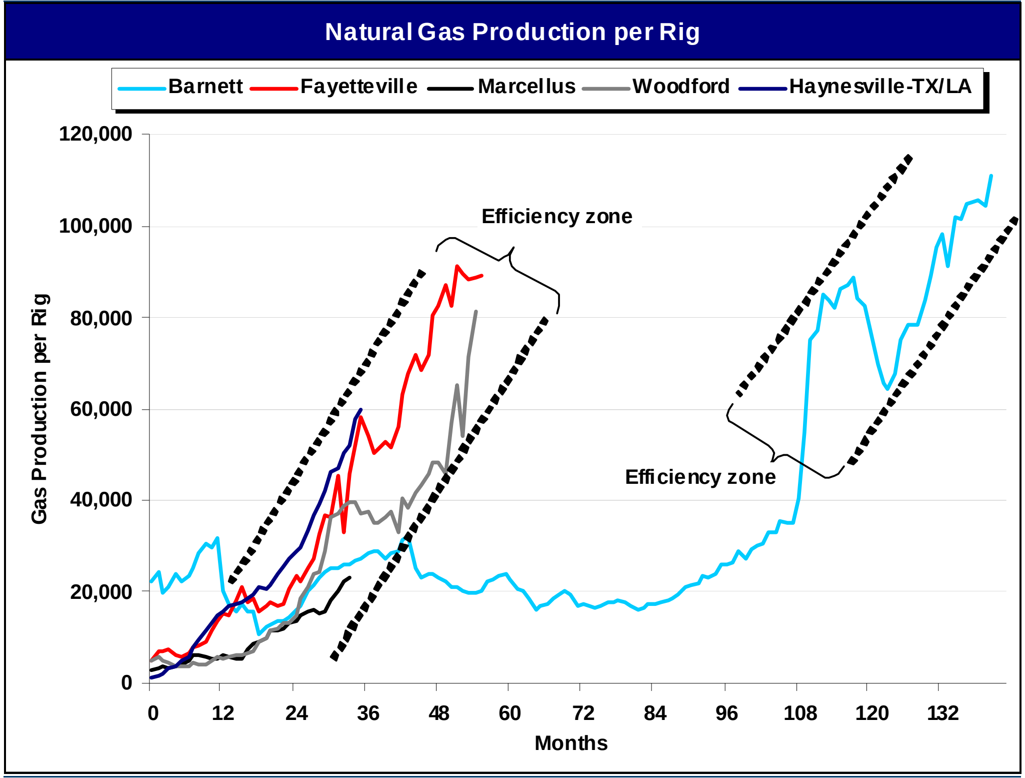
Exhibit 52: **US Rigcount Trends: Declining Natural Gas Drilling Activity**



Source: Company data, Credit Suisse estimates.

Despite reductions in natural gas drilling activity, there have been sharp improvements in productivity that have more than offset the impact from a lower gas rigcount. These efficiency improvements include the increased use of high-spec land rigs that are better suited to drill horizontal wells much more efficiently than conventional rigs, increases in lateral lengths that have boosted production rates per well, advances in stimulation technology such as cluster fracs as well as microseismic data to optimize the placement of laterals, and widespread use of PDC drill bits. Exhibit 53 illustrates the significant gains in efficiency in all 5 plays. During the first decade of development in the Barnett, production per rig trends were largely static, with production trends essentially oscillating with rigcount trends. Over the past 3 years, there has been a dramatic improvement in rig efficiency as these newer technologies have been adopted even in 'older' plays such as the Barnett.

Exhibit 53: Rig Efficiency Has Overwhelmed Declines in Activity



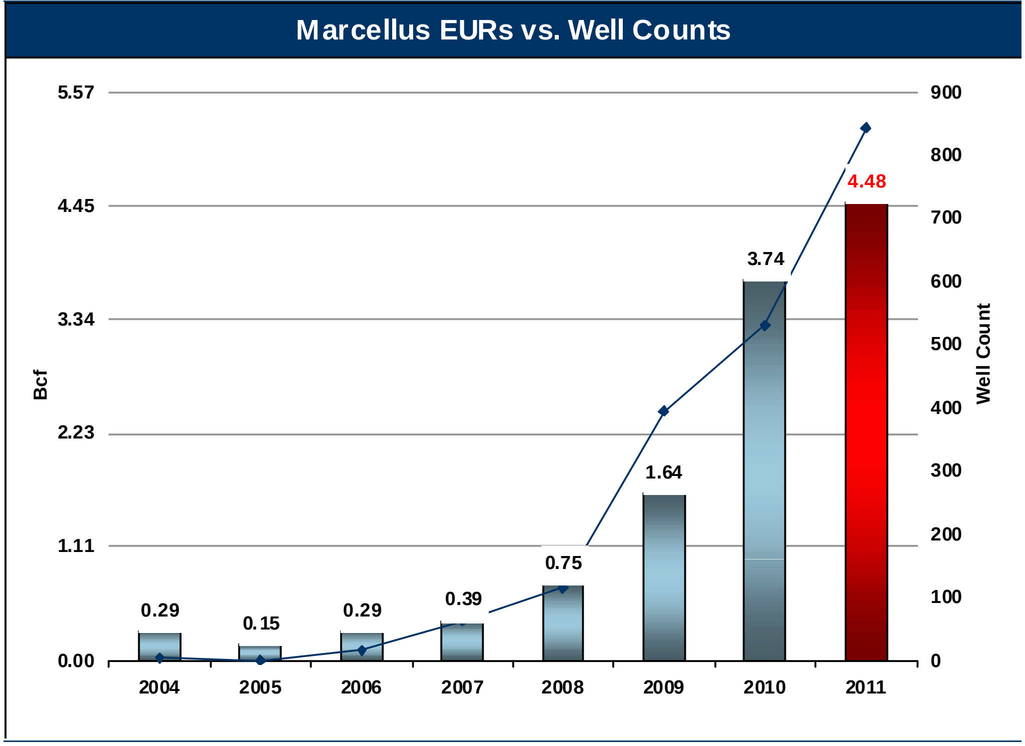
Source: Company data, Credit Suisse estimates.

High spec land rigs can drill more wells per year; longer laterals and advances in stimulation improves recovery per well; these learnings can improve the performance of older plays as well as new ones

Beware the Surge in Marcellus Shale Production

While there have been improvements in all of these key plays, the key near-term challenge for the supply picture is the Marcellus Shale play, which is in the early stages in development. Unlike the other key natural gas plays, efficiency gains associated with the Marcellus have been modest despite significant increases in EURs. Utilizing HPDI data, we estimate the average EUR in the Marcellus Shale (Pennsylvanian acreage only) has increased to 4.48 bcf from 3.74 in 2010 and only 1.64 bcf in 2009. As such the gains in production have largely been driven by increases in activity as producers have been infrastructure constrained given limited takeaway capacity in Northeast Pennsylvania and limited gas processing capacity in Southwest Pennsylvania.

Exhibit 54: **Historical Trend in Pennsylvania Marcellus EURs**



Source: Company data, Credit Suisse estimates.

In order to quantify the potential impact of the Marcellus Shale to the natural gas supply picture, we created a model to forecast natural gas production from the Marcellus. Our model is based on a blended EUR across the basin using actual well results and a significant inventory of locations that should provide decades of drilling opportunities (Exhibit 55).

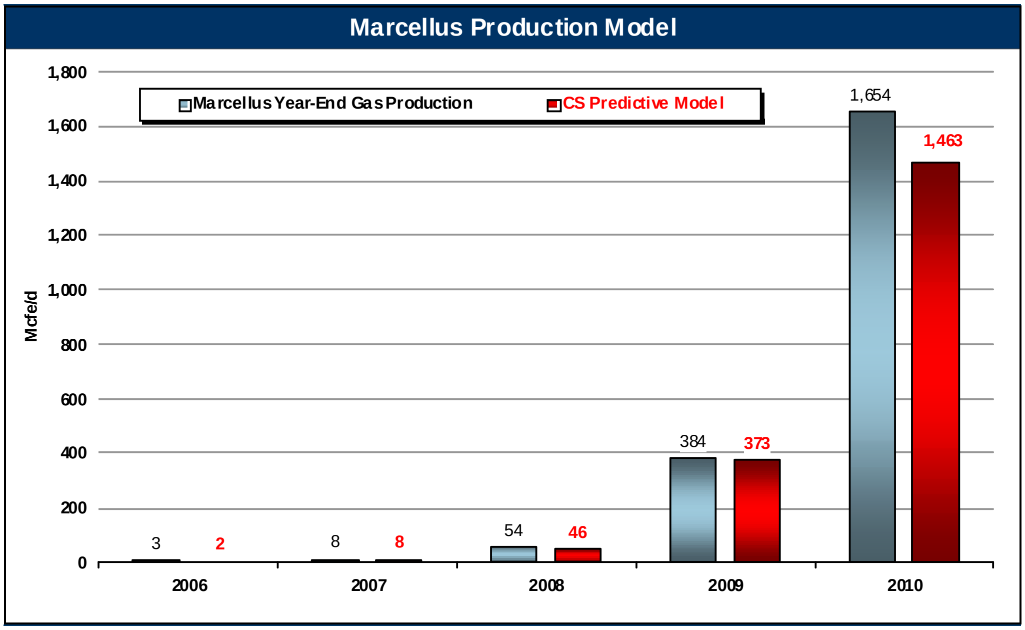
Exhibit 55: **Estimated Drilling Locations**

Risked Location	
Estimated Undeveloped acreage	8,438,648
Spacing (acres)	120
Unrisked locations	**70,322**
Estimated Success rate	80%
Risked locations	**56,258**

Source: Company data, Credit Suisse estimates.

Exhibit 56 compares our predictive model for the Marcellus Shale relative to actual year-end natural gas production as reported by HPDI. Historically, our model has been a fairly accurate gauge for year-end gas production. While our modeled production for year-end 2010 of 1.46 bcf/d trailed actual production of 1.65 bcf/d by 13%, we note our year-end 2011 production forecast of 3.1 bcf/d appears on track judging by recent pipeline flows.

Exhibit 56: Historical Marcellus Production Relative to CS Predictive Model



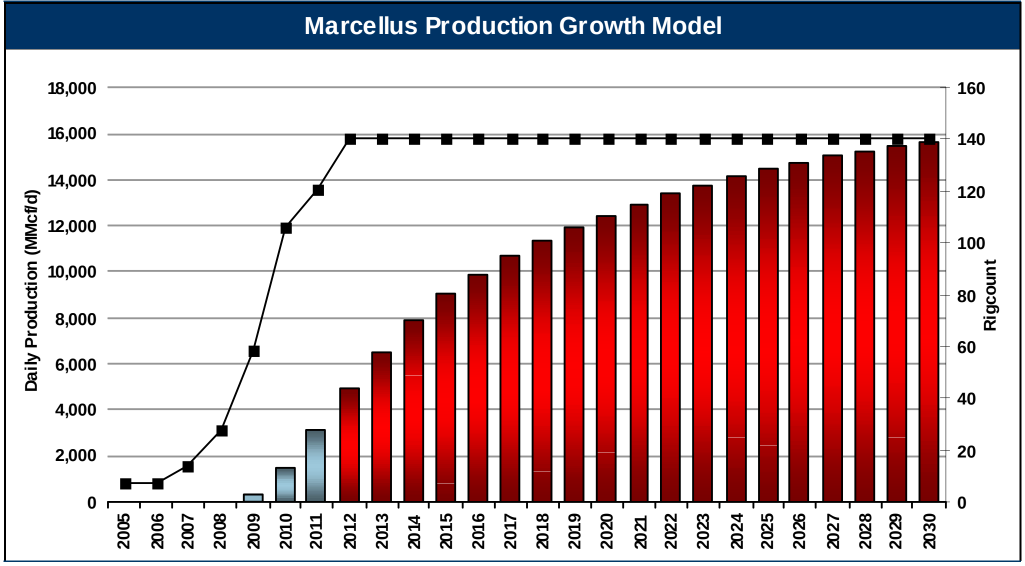
Source: Company data, Credit Suisse estimates.

Exhibit 57 illustrates our Marcellus Shale production forecast through 2030. Our model assumes a long-term rigcount forecast of 140 and 20% efficiency gains from pad drilling as the play moves into a fuller development model. While we believe our efficiency gain assumption is conservative, we do believe infrastructure challenges could limit further improvements in efficiency relative to other plays such as the Haynesville or Fayetteville.

Our model suggests Marcellus production could triple between 2011 and 2015 to more than 9 bcf/d although we acknowledge actual production will most likely be constrained by infrastructure bottlenecks from the required midstream build-out (i.e., productive capacity is likely going to exceed pipeline/gas processing capacity).

Nine bcf/d is possible from the Marcellus by 2015 with the right infrastructure; gas production in the Northeast will also benefit from the emerging Utica shale

Exhibit 57: Forecast Marcellus Shale Production: 9 BCF/D Possible by 2015

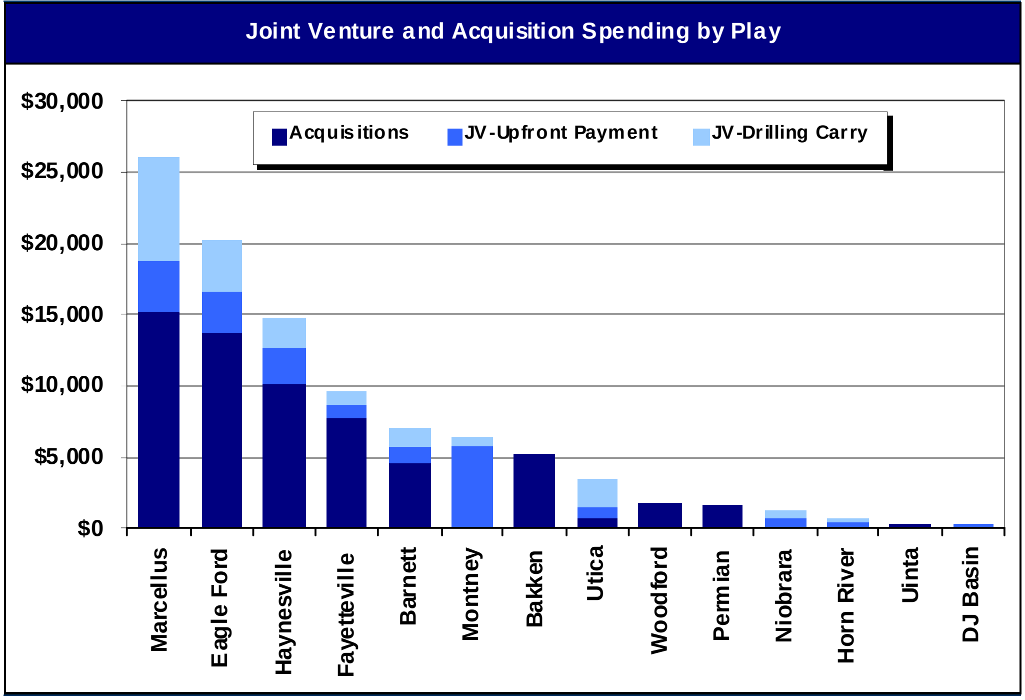


Source: Company data, Credit Suisse estimates.

Majors and Foreign Oils Set for Capex Ramp

Another factor that could limit a quick reset in the natural gas market despite reductions in gas drilling activity is rising activity from Major/Foreign Oils looking for some return from their massive investments in shale acreage. Between 2008 and 2011, there were $129 billion of acquisitions and JV deals, including $110 billion of upfront payments and $19 billion of drilling carries. As shown in Exhibit 58, the bulk of the shale related investments were earmarked for the Marcellus (20%), Eagle Ford (16%), Haynesville (11%), and Fayetteville (7%).

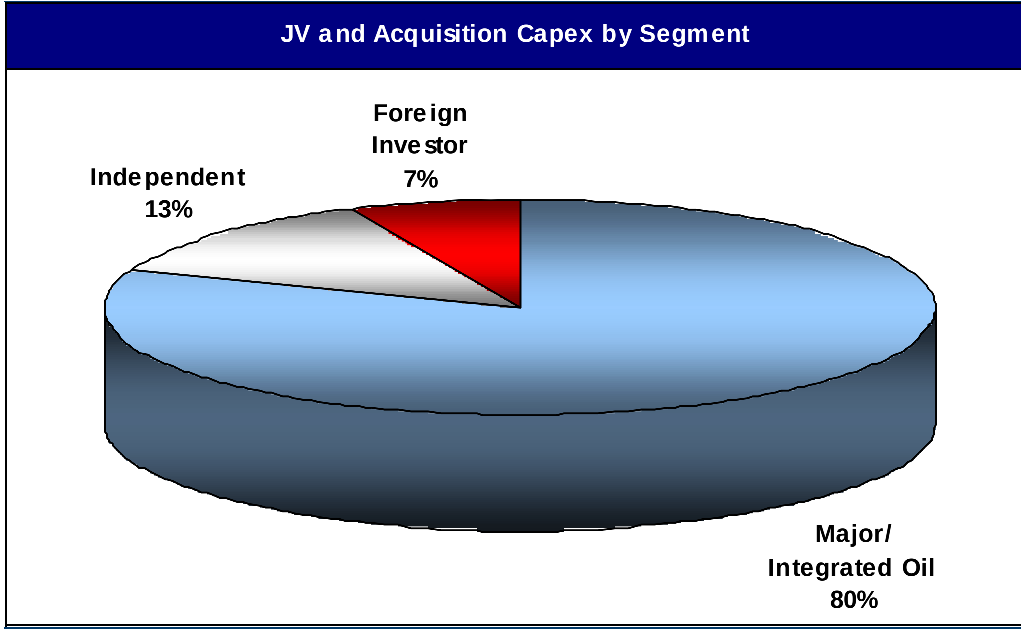
Exhibit 58: **Joint Venture and Acquisition Spending by Play**



Source: Company data, Credit Suisse estimates.

Of the $129 billion total, Major Oils and Foreign buyers with lower costs of capital and better balance sheets represented 80% and 7% of funds exposed versus only 13% for Independents.

Exhibit 59: Majors and Foreign Buyers Dominate Shale JV and Acquisition Spending



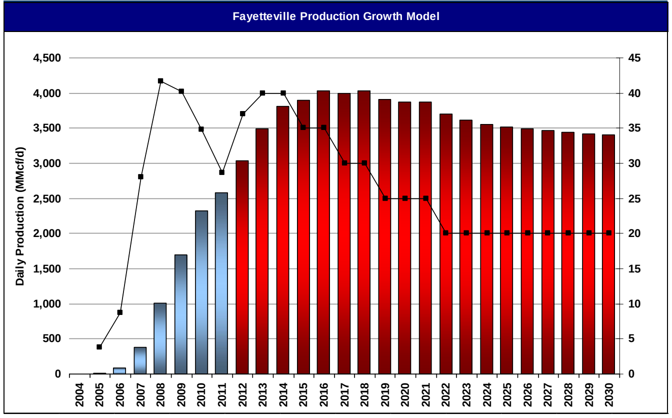
Source: Company data, Credit Suisse estimates.

Following these significant acreage investments, we believe Majors are likely to increase activity despite challenging gas drilling returns as they look for even a modest return on their significant investments as well as to boost their shale related expertise. Analysis of land rig newbuild data suggests there have been 267 land rig newbuild orders between 2010 and 2011. While the public land drillers do not report the exact number of newbuild by customer group, anecdotal commentary with land drillers indicate that Major and Foreign Oils have meaningfully increased their newbuild order activity and could represent approximately one-third of recent newbuild activity.

This is consistent with public commentary from Majors such as BHP. In February 2011, BHP announced a $4.75 billion agreement to purchase Chesapeake's Fayetteville Shale assets, which included 10 tcf of risked resources on 487K net acres. In November 2011, BHP unveiled its plan to increase its operated rigcount in the Fayetteville from 6 to 20 by placing orders for 14 newbuild land rigs. Given the sharp increase in activity, we believe Fayetteville gas production (see Exhibit 60) will continue to grow despite the modest reduction in activity recently announced by Southwestern (SWN). We believe overall Fayetteville production could increase by more than 1 bcf/d from 2011 to 2013 despite weak gas prices given this surge in activity by BHP (Note: BHP is currently producing 435 mmcf/d with a rigcount of 6).

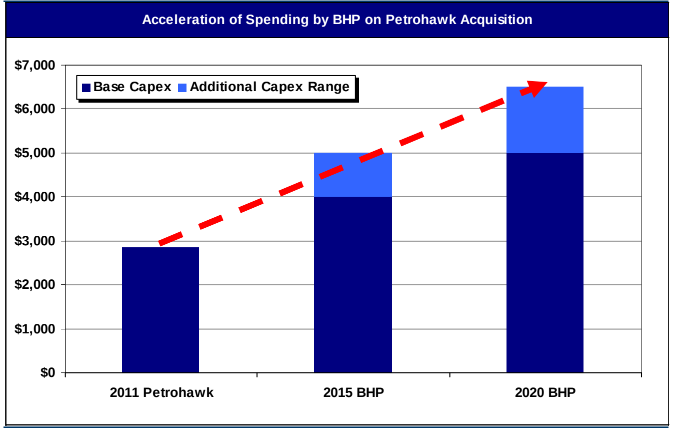
Following BHP's acquisition of Petrohawk in July, the company announced plans to meaningfully boost capex as shown in Exhibit 61. While BHP did not provide specific capex commentary by play, we would note that the company expects to boost capex by a range of 40% to 75% in 2015 from HK's $2.85 billion budget in 2011 given its stronger balance sheet to allow for simultaneous development of the Eagle Ford and Haynesville and possibly the Permian. We expect other Majors to pursue a similar growth strategy from acquired acreage, although the magnitude of the increases may not be as aggressive as indicated by BHP.

Exhibit 60: Fayetteville Shale Production Growth Model



Source: Company data, Credit Suisse estimates.

Exhibit 61: BHP Spending Plans for HK Assets

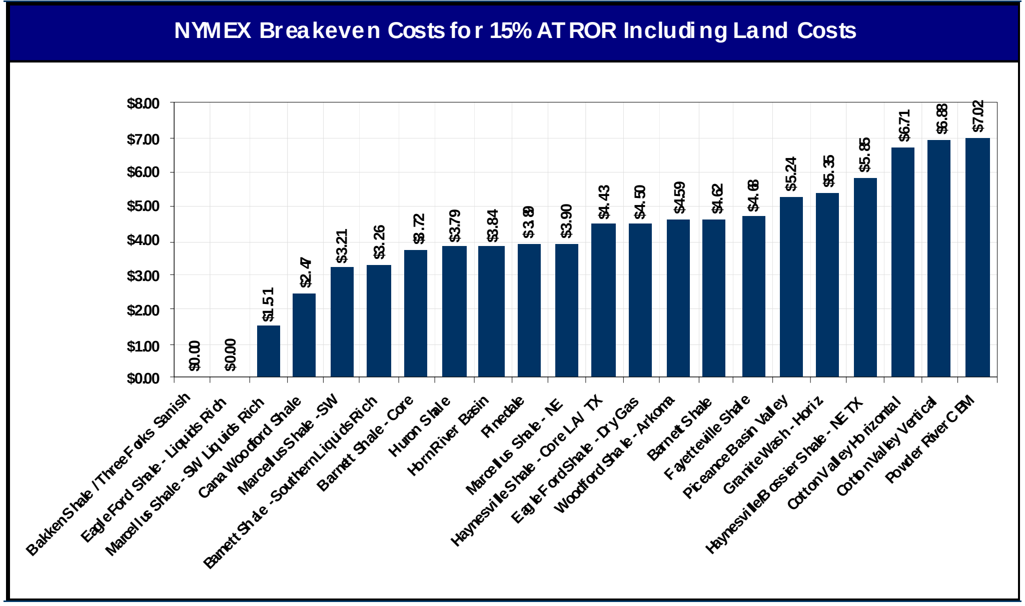


Source: Company data, Credit Suisse estimates.

Gas Activity May Not Be As Vulnerable As It Appears

One constructive aspect about natural gas fundamentals is the fact that most natural gas plays are uneconomic at current prices (Exhibit 62), which should support reduced natural gas drilling activity. In response to low prices, the natural gas rigcount has already declined 118 rigs, or 13%, from recent highs. We believe prices will undoubtedly rise as gas prices cannot stay below the marginal cost of supply for a extended period without a supply response.

Exhibit 62: Break-Even NYMEX Costs per Play

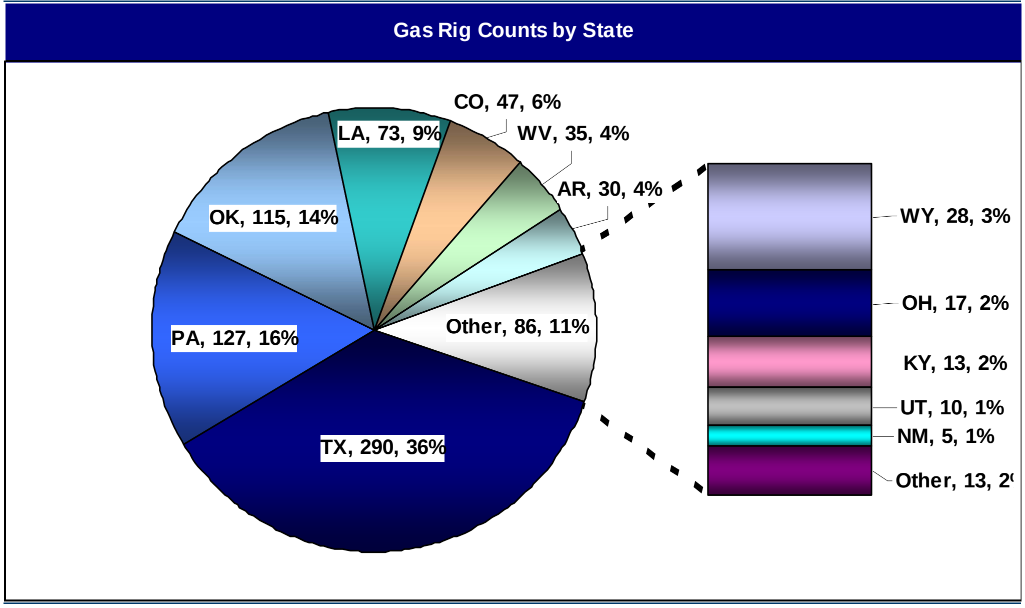


Source: Company data, Credit Suisse estimates.

To assess the potential for a sharp natural gas led rigcount decline, which could potentially rebalance the gas market quickly, we analyzed the current distribution of land rigs classified as gas rigs by the Smith Rigcount. As of mid-December, there were 803 gas rigs including:

- 290 rigs in Texas;
- 127 rigs in Pennsylvania;
- 115 rigs in Oklahoma;
- 73 rigs in Louisiana;
- 47 rigs in Colorado;
- 35 rigs in Virginia;
- 30 rigs in Arkansas;
- 86 rigs in Other States (28 in Wyoming, 17 in Ohio, 13 in Kentucky, 10 in Utah, 5 in New Mexico, 13 Miscellaneous).

Exhibit 63: **Natural Gas Rigs by State**



Source: Company data, Credit Suisse estimates.

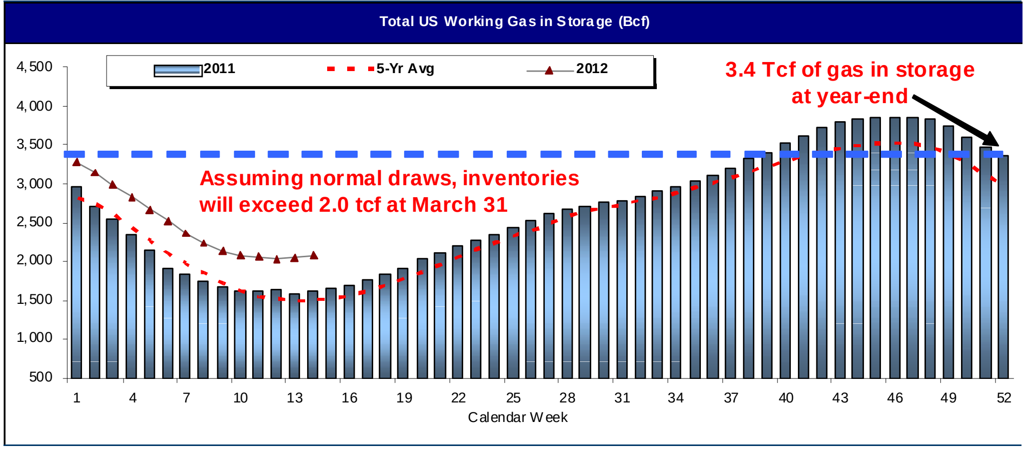
To test the vulnerability of gas rigs deployed in the field, we further broke down the rigcount into specific counties within the States. For these counties, we examined oil yields relative to natural gas yields. Given high oil prices, producers can generate positive returns even if there are modest quantities of associated liquids. For example, the overall revenue from a well increases by $1.50/MMBtu if the well has a 10% overall liquids yield under a $90/bbl oil price. We used the 10% oil threshold to test for vulnerability (i.e., if liquids yields in a county were below 10%, we classified the rig as vulnerable given low gas prices or vice versa). In addition, if the gas rig was located in a low cost play such as the Marcellus or the Pinedale, we tested the economics by county to asses the vulnerability in lower cost plays. For example, our analysis indicated that rigs drilling for dry gas in Pennsylvania counties such as Tioga, Susquehanna, and Lycoming would not be vulnerable despite low gas prices given outstanding well performance. On the other, we classified rigs in Pennsylvania counties such as Butler, Cameron, and Clarion as vulnerable given lower IP rates and EURs. A summary of our key findings:

- 473 out of 803 rigs, or 59%, of rigs classified as gas rigs do not appear vulnerable assuming oil prices remain above $90 per bbl.
- 330 rigs appear potentially vulnerable given low gas prices including conventional gas production as well as rigs deployed in dry gas prone plays.
- Assuming 50% of rigs in the vulnerable category are let go, we believe the gas rigcount could decline by approximately 165 more rigs. We believe it is highly unlikely that all rigs in vulnerable markets such as the Haynesville would be layed-down given lease expiration as well as the presence of long-term supply agreements for rigs, services, and midstream.
- If an additional 10% of rigs in the nonvulnerable bucket are dropped, that would imply an additional 47 rigs or 212 rigs in total.

Marcellus Producers Could Feel Some Pain This Summer

Exhibit 64 illustrates the bloated inventory picture, with natural gas inventories 347 bcf or 10% above 5-year average levels. Assuming winter draws are consistent with 5-year average levels, natural gas inventories are poised to exceed 2.0 Tcf at the end of March, more than 500 bcf, or 33%, above normal levels, which would likely keep a lid on gas prices in 2012 even if gas directed drilling activity continues to slide.

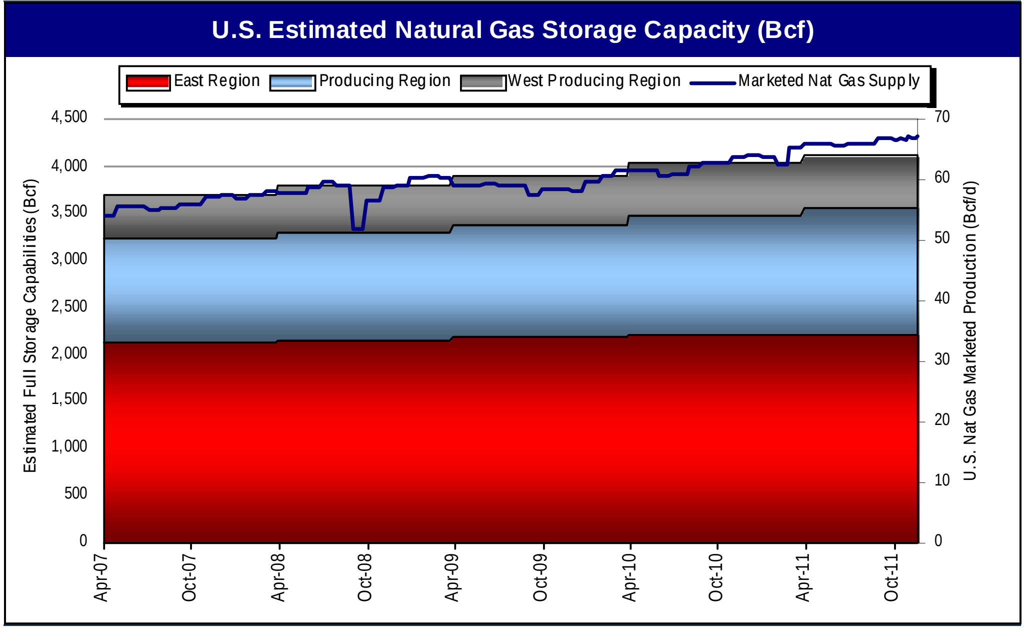
Exhibit 64: Natural Gas Storage Inventories



Source: Company data, Credit Suisse estimates.

Exhibit 65 illustrates the relationship between natural gas storage capacity and US natural gas supply. Note increases in productive capacity have grown faster than storage since 2007. Unless there is a prolonged cold snap or a steep decline in drilling activity, we see the growing potential for shut-ins later in 2012 as there doesn't appear to be enough storage to handle surging domestic volumes.

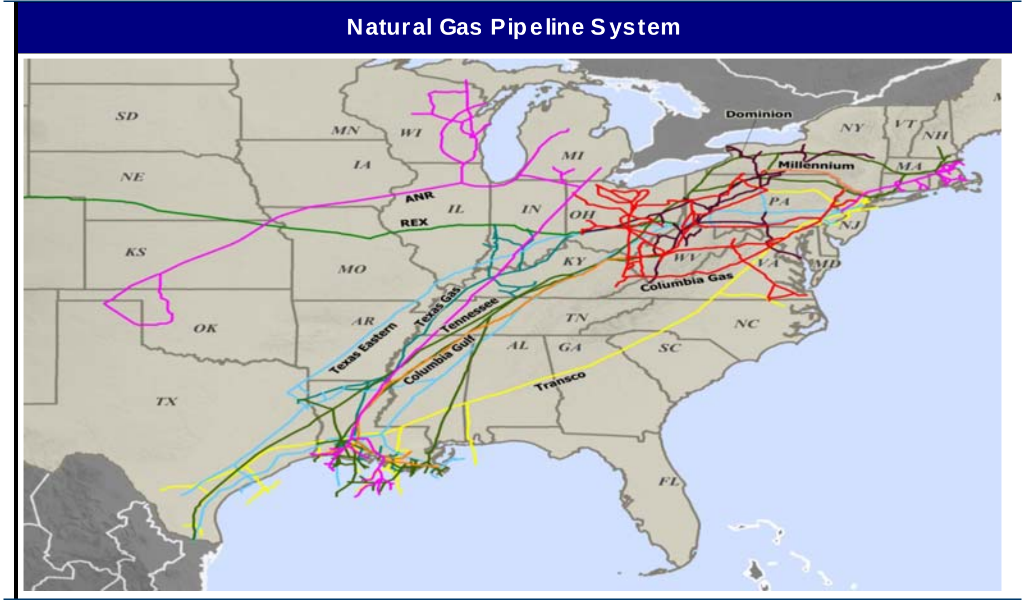
Exhibit 65: US Natural Gas Storage Capacity vs. Natural Gas Supply



Source: Company data, Credit Suisse estimates.

Exhibit 66 illustrates the flow of the key pipelines in the US natural gas system. In general, the US pipeline system was designed to move gas eastward from the Producing Region and the Rockies to population centers in the Northeast.

Exhibit 66: Natural Gas Pipeline System



Source: Company data, Credit Suisse estimates.

Exhibit 67 illustrates the changing complexion of the US Supply picture. Since the 1980s, the biggest percentage increases in supply have been driven by the East and West Regions, with production increasing by 309% and 216%, respectively, from lower bases. While there has been significant infrastructure development in the West, with major pipeline projects such as Rex and Ruby, there have been more limited pipeline expansion projects completed in the Marcellus.

Exhibit 67: **Changing Complexion of US Natural Gas Supply (Bcf/d)**

Gas Production Per Day	1980s	1990s	2000s	2009	2010	Dec-10	% Change Since 1980s
Producing Region	31.8	32.9	34.2	39.2	41.4	43.0	35%
West Region	4.7	7.3	12.3	15.4	15.2	14.9	216%
East Region	1.2	2.0	2.5	2.9	3.5	4.7	309%
Federal Offshore	12.4	13.6	10.2	6.9	6.3	5.9	-52%

Source: Company data, Credit Suisse estimates.

“Back haul” arrangements are a short-term fix for the glut of Marcellus gas, but we worry about storage this summer. Marcellus gas will undoubtedly displace natural gas from other markets given lower transportation costs on a longer-term basis, but we believe the surge in Marcellus production that is slated to occur over the next several months could lead to even forced shut-ins in the Marcellus given the bloated storage picture. While we view this as a short-term challenge, we believe this is an important issue to follow as we enter 2012 given the significant outperformance of the Marcellus producers relative to the peer group.

US Power Markets: Rethinking Demand Outlook

We are growing more concerned that the medium- to longer-term US power demand outlook needs to be reconsidered as the impact of state efficiency programs and advances in device efficiency slows the trajectory of growth. We appreciate demand growth forecasts tend to fall into the school of art over science but are seeing issues that could help account for the disappointing usage trends seen at utilities this year with knock-on effects into the future.

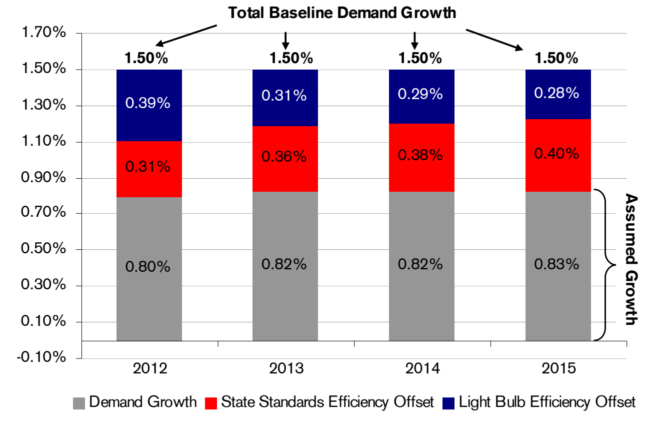
Efficiency is set to have a meaningful impact on US electricity demand growth

We see potential demand growth reductions of 0.6-0.8% per year relative to a base normalized growth assumption of 1.5% per annum, or a ~50% drop in the rate of electricity demand growth. We come to these reductions two ways:

- State specific energy efficiency programs and enforcement of light bulb rules for Residential customers in states without specific standards;
- Buildup of efficiency gains focused on Residential customers through the light bulb standards, improvements in HVAC performance, and general appliance efficiency gains.

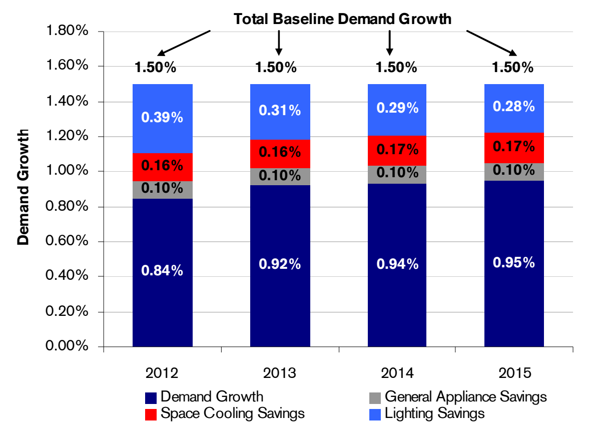
Exhibit 68 and Exhibit 69 show the change in annual demand growth rates under the two scenarios and more illustratively Exhibit 70 and Exhibit 71 show the cumulative impact on power demand with the compounding impact of efficiency.

Exhibit 68: Demand Growth w/ State / Light Bulb Efficiency



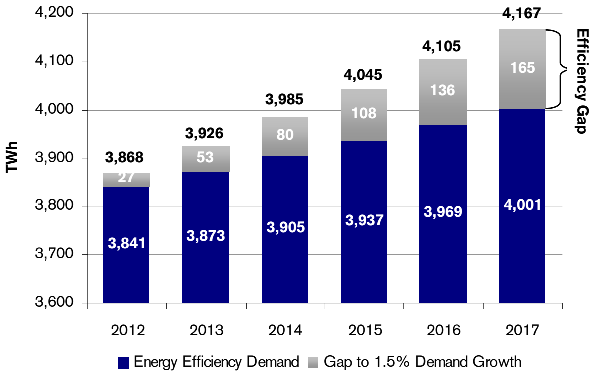
Source: EIA, Company data, Credit Suisse estimates.

Exhibit 69: Demand Growth w/ Appliance Efficiency



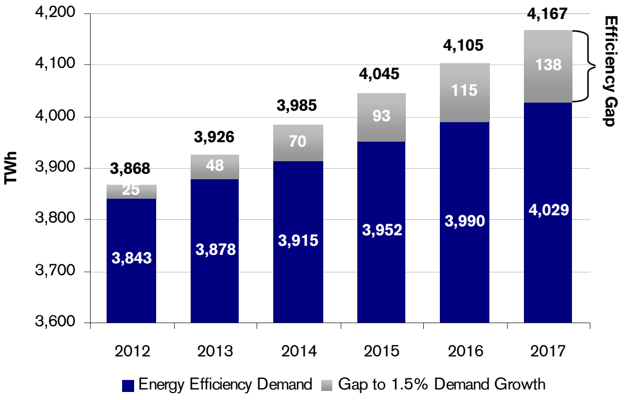
Source: EIA, Company data, Credit Suisse estimates.

Exhibit 70: **Cumulative Impact w/ State / Light Bulb Standards**



Source: EIA, Company data, Credit Suisse estimates.

Exhibit 71: **Cumulative Impact w/ Appliance Efficiency Standards**



Source: EIA, Company data, Credit Suisse estimates.

Not all regions are created equal

And, while the overall market impact is fairly meaningful, narrowing the conversation to specific markets is even more telling. Exhibit 72 shows the impact to power demand growth by ISO using the state specific targets and light bulb impact in states without standards.

Notably, the Northeastern markets are the most exposed to energy efficiency as virtually every state has a target program in place with PJM cumulatively targeting a 1.03% reduction, NEPOOL 1.51%, and NYISO 2.00%.

Exhibit 72: **Energy Efficiency Savings by ISO (w/ Light Bulb Efficiencies)**

	Year									
ISO	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Average**
NY ISO	-2.00%	-2.00%	-2.00%	-2.00%	-2.00%	-2.00%	-2.00%	-2.00%	-2.00%	-2.00%
ISO NE	-1.54%	-1.54%	-1.52%	-1.51%	-1.51%	-1.50%	-1.49%	-1.48%	-1.48%	-1.51%
CAISO	-1.37%	-1.37%	-1.37%	-1.37%	-1.37%	-1.37%	-1.37%	-1.37%	-1.37%	-1.37%
PJM	-0.87%	-0.90%	-0.94%	-0.98%	-1.03%	-1.08%	-1.13%	-1.17%	-1.17%	-1.03%
PJME	-0.95%	-0.93%	-0.92%	-0.91%	-0.91%	-0.91%	-0.90%	-0.90%	-0.90%	-0.91%
PJMW	-0.60%	-0.80%	-1.00%	-1.20%	-1.40%	-1.60%	-1.80%	-2.00%	-2.00%	-1.38%
MISO	-0.76%	-0.77%	-0.79%	-0.79%	-0.78%	-0.78%	-0.78%	-0.77%	-0.77%	-0.78%
WECC	-0.56%	-0.52%	-0.51%	-0.52%	-0.52%	-0.52%	-0.52%	-0.52%	-0.52%	-0.52%
ERCOT	-0.39%	-0.31%	-0.29%	-0.28%	-0.28%	-0.28%	-0.28%	-0.28%	-0.28%	-0.30%
SPP	-0.37%	-0.30%	-0.29%	-0.27%	-0.27%	-0.27%	-0.27%	-0.27%	-0.27%	-0.29%
SERC	-0.35%	-0.31%	-0.29%	-0.28%	-0.28%	-0.28%	-0.28%	-0.28%	-0.28%	-0.29%
US Overall	-0.70%	-0.68%	-0.68%	-0.67%	-0.68%	-0.68%	-0.69%	-0.69%	-0.69%	-0.69%

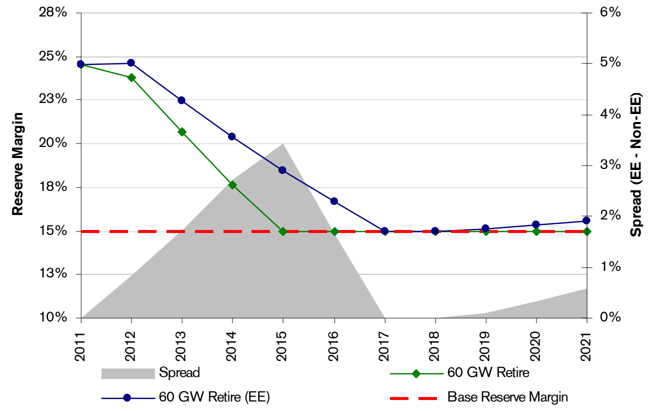
Source: Center For Climate and Energy Solutions, EIA, Credit Suisse estimates.

With a Need to Watch Reserve Margins

We think this trend is important and arguably underappreciated as we layer in the efficiency adjusted demand growth forecasts into our reserve margin calculations, with equilibrium getting pushed out by 1-3 years (Exhibit 73 and Exhibit 74). And, with Residential customers likely accounting for a greater share of the demand reductions we are calculating, we can see a case for a greater drag on peak power demand that would further weigh on reserve margin tightening since Residential usage tends to have a greater bias toward peak periods than other customer classes.

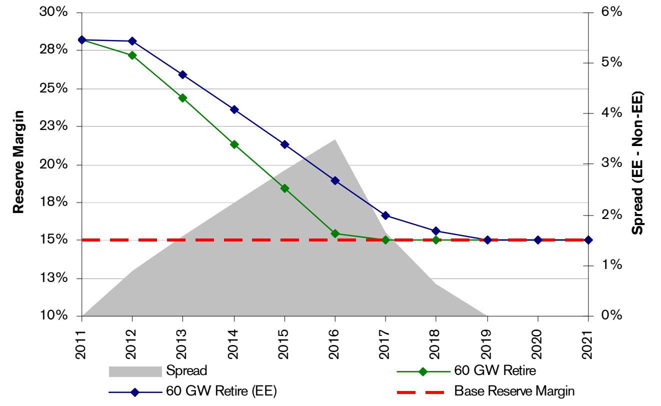
We need to monitor this trend especially for competitive generators since so much economic value is being derived from capacity revenues that are priced on reserve margins; if the market fails to tighten as quickly as expected due to slower demand growth we could see risk to this story although the slow uptake/visibility of efficiency could leave the conversation longer-dated.

Exhibit 73: PJM Reserve Margin



Source: SNL, Credit Suisse estimates.

Exhibit 74: US Overall Reserve Margin



Source: SNL, Credit Suisse estimates.

Commodity Market Impact

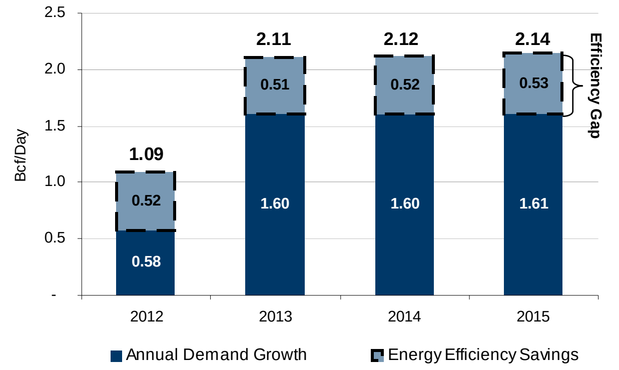
Efficiency could shave 3 bcf/d off 2017 US natural gas demand growth

The most bullish story for natural gas supply-demand fundamentals has been the expected growth in demand from power generators to meet the combination of natural electricity demand growth as well as substitution with gas generation for retiring coal plants due to pending EPA policy.

We see this as still an important theme but a change in trajectory for power demand growth would act as a partial foil to the substitution thesis. In Exhibit 75 we show the impact on natural gas demand growth relative to our current annual growth forecast, slowing the rate of growth by ~0.50 bcf / day. Exhibit 76 shows the cumulative outlook for natural gas demand growth that could be 25% lower than expected in 2017, again highlighting the compounding drag on the rate of growth.

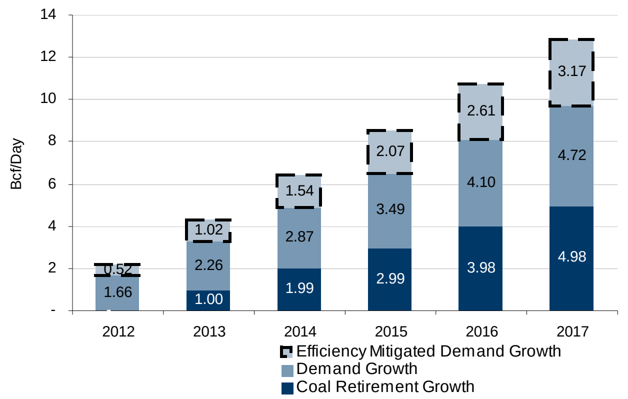
We need to stress that natural gas demand will continue to grow with more power generation use but that the rate of growth could look slower than what is underpinning a more bullish natural gas outlook.

Exhibit 75: **Annual Efficiency Impact on Gas Demand**



Source: Company data, Credit Suisse estimates.

Exhibit 76: **Cumulative Impact on Gas Demand**



Source: Company data, Credit Suisse estimates.

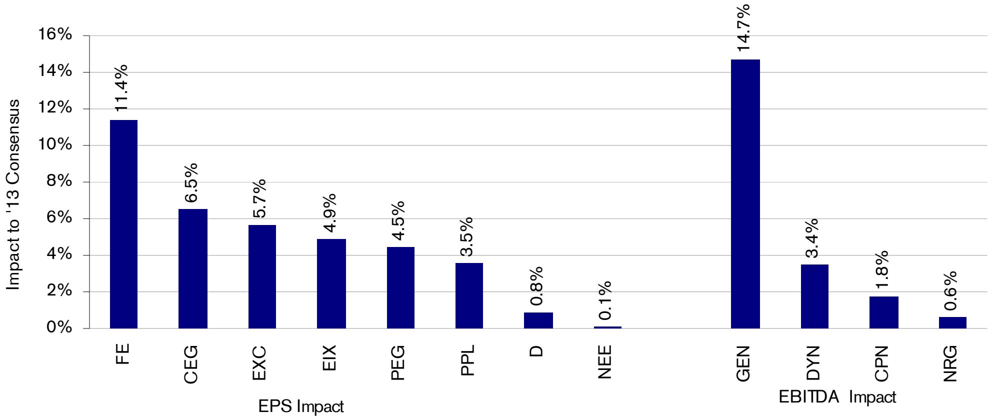
Stock Implications

We expect the energy efficiency impact to be a slow-moving event with changes in consumption more readily blamed on other, equally hard to quantify factors including (a) still slow economy and (b) weather normalization. Further, we don't see obvious catalysts/markers for this trend like we do with EPA rules that have explicit deadlines (when followed…) or PJM capacity auctions (that happen every May).

We think lower demand growth will be an industry-wide issue but will likely be more pronounced in markets with slower underlying demand growth further mitigated by more ambitious demand reduction programs like the Northeastern US.

Competitive power generators could in turn bear the greatest burden with delays in supply-demand recovery especially since so much more of the economic value of a power plant is coming from capacity markets (which are a function of reserve margins aka supply-demand), particularly in a low commodity price environment. We would recommend watching the variables used in modeling future capacity auctions, particularly around demand projections for both a reset to capture slow prompt demand trends and eventually a slowing in the modeled rate of growth. To help put in context, Exhibit 81 shows the EPS sensitivity to $25 / MW-day changes in PJM capacity prices.

Exhibit 81: **% Impact to 2013 Earnings of $25 MW/Day Change in PJM Capacity Prices**



Source: PJM, Factset, Company data, Credit Suisse estimates.

Regulated utility impact will vary by region although notably the states with the most ambitious energy efficiency goals generally have the best utility protections against volumetric exposure with either full revenue decoupling (not volumetric) or allowing revenue adders to offset efficiency specific lost revenues. For utilities without protections, we generally see less impact from energy efficiency although it will be an issue to watch for all utilities both in how they are able to manage cost inflation (generally volume driven growth acts as an inflation hedge/cover for rate base growth) as well as rate base growth if less new generation capacity is required.

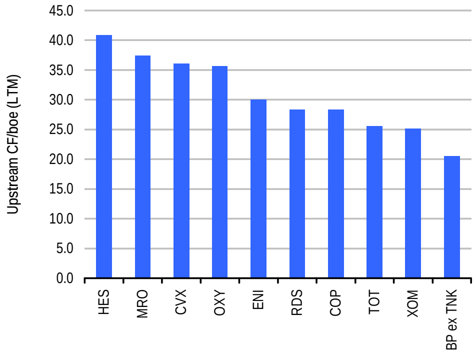
Integrated Oils—How Will Majors Spend $200bn of Excess Cash?

Last year in Energy in 2011, we made much of the fact that Big Oil's cashflow outlook was being underestimated. This is partly a function of their greater leverage to Brent oil prices—the majors generally have a higher share of oil production and oil-priced linked international gas production in the mix, particularly relative to US E&Ps who are more exposed to declining US natural gas prices. It is also a function of rising underlying cashflow per barrel margins on their new upstream projects. Although we and many investors have historically criticized the majors for declining free cashflow and limited top-line growth, the majors have in fact invested heavily to increase their sensitivity to higher oil prices through the choice of fiscal regime and invested to defer their maintenance capital requirements by bringing on longer lived production, e.g., LNG and heavy oil.

We believe M&A is set to accelerate, notably in liquid shales

As the major's free cashflow rises, in *Energy In 2012—Transitions* we focus on where the majors will deploy their cashflow in 2012 and beyond. Indeed, in our triple-digit oil outlook, we calculate that the majors should have $200bn of free cashflow over 2012-2015 after paying dividends and capex at their discretion and without any releveraging of their underutilized balance sheets.

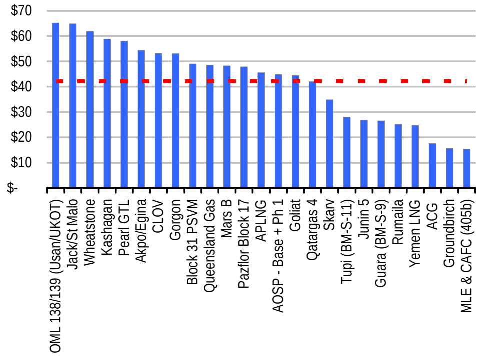
Exhibit 82: Upstream Cashflow per Barrel Has Room to Rise, Even from Recent Levels



Source: Company data.

Avg Brent & WTI price LTM): $105.32/bbl & $92.82/bbl

Exhibit 83: New Projects Have Higher Midcycle Cashflow than in 2011



Source: Company data.

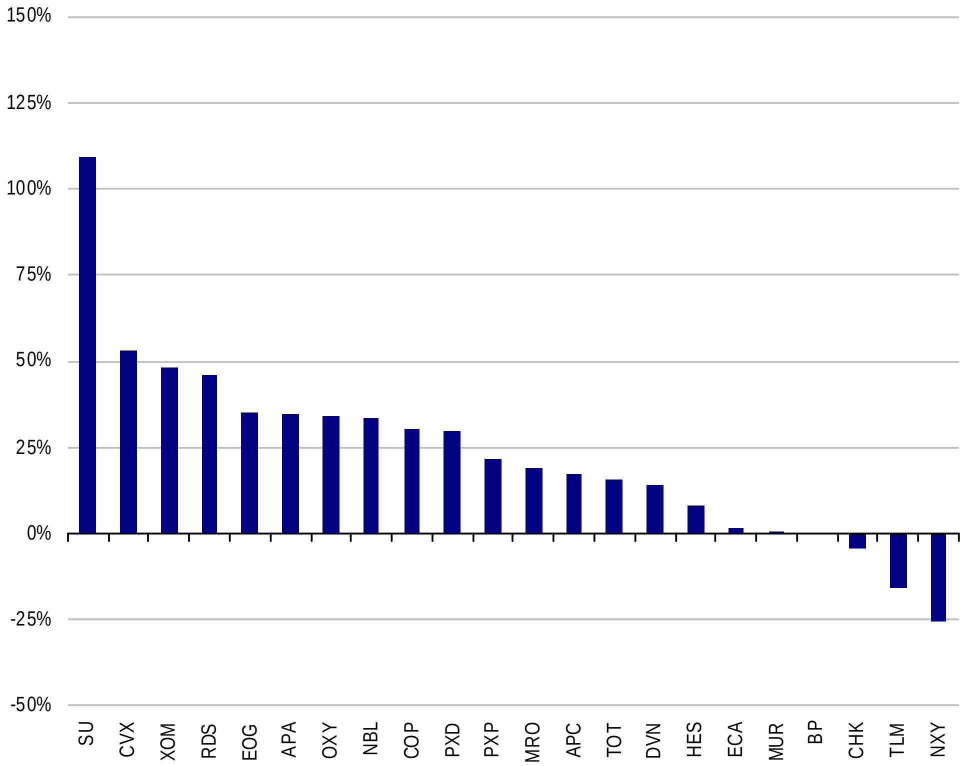
High CF/BBL on new production should allow cashflow margins to expand; as cashflow rises, where will Big Oil spend its excess cash?

2011 Review: Our Cashflow Thesis Is Working at XOM, CVX, and RDS

Looking back over the last 12 months, we conclude that **our thesis of strong cash flow generation has been demonstrated in 2011 at Shell, XOM, and CVX but not by everyone.** To be fair, a number of unforeseen issues in 2011 weighed down on Majors' cash flow—such as war in Libya, a lengthier "permitorium" in the GoM than we forecasted at the end of 2010, and heavy maintenance in several parts of the world (North Sea and Angola among others). Other reasons for disappointments include rising upstream cost inflation which blunts Big Oil's leverage to high oil prices, and weaker-than-expected US gas prices and European refining margins. Despite these disappointments, the Majors lead the leaderboard for CFPS growth in 2011.

Although the European majors fell short of our earnings forecast, overall cashflow growth was among the best in the sector

Exhibit 84: **Change in CFPS from 1Q10 to 3Q11**



Source: Bloomberg, Credit Suisse estimates.

Operating Cash Flow Growth to Improve Further from 2012 Onwards

RDS has the best momentum into 2012

In part, a lack of positive cash flow surprises in 2011 is due to timing. As we pointed out last year, **the increase in cash flow from new project start-ups is still a few years away for most companies.** Shell was the only major which had significant upstream start-ups in 2011 (i.e. Pearl GTL, Qatargas 4, AOSP Expansion). Looking into 2012, we expect the continued ramp-up of Pearl GTL to further boost Shell's cash flow.

Companies such as Total or Eni will show some underlying cash flow growth in 2012-13 thanks to the start-up of large oily projects (Pazflor, Usan, Kashagan) which will be accretive to cash margins. Looking further out, growth from deepwater production in the Gulf of Mexico, Brazil and West Africa will start to have a meaningful impact on cash flow only in 2014-15. Finally, cash flows from the next wave of new long-life assets (LNG, oil sands) will only come in 2015-17, particularly for CVX.

What Will the Majors Do with Their Cash Flow?

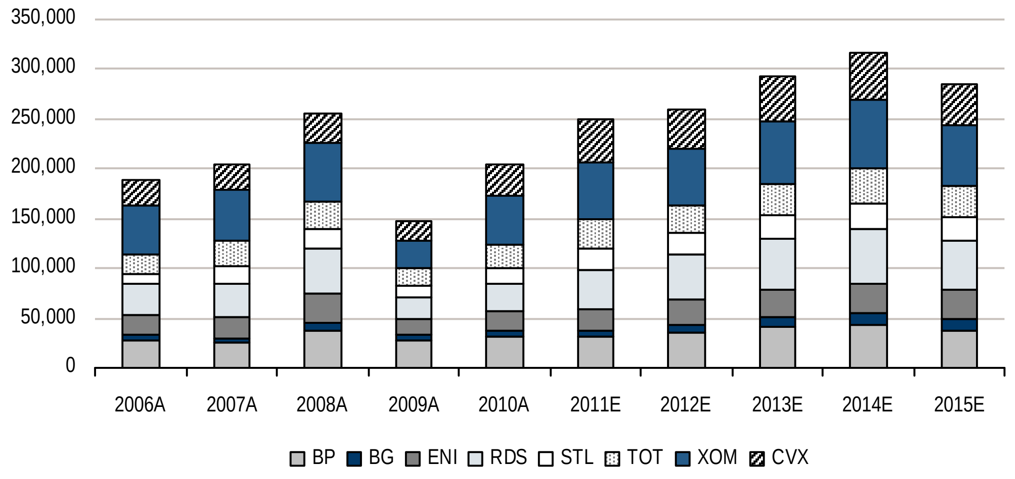
$200bn of excess cash after capex and dividends generated cumulatively over from 2012-2015

The Majors are **generating near-record amounts of *precapex* cash flow, courtesy of high oil prices**. On our estimates, Big Oil is set to generate $295bn of operating cash flow in 2012 (at $105/bbl Brent), in line with its 2008 peak (at $100/bbl) and despite a weaker downstream. Over the 2011-15 period, we estimate that operating cash flow can rise by c.4% p.a., even if oil prices fall back to $90/bbl in 2015, implying a better underlying performance than top-line production growth of 4%.

We believe a combination of rising cashflow and longer project life will translate into higher free cashflow at the majors over time. Indeed we calculate that the majors should have $200bn of free cashflow over 2012-2015 after paying dividends and capex at their discretion and without any releveraging of their underutilized balance sheets.

Exhibit 85: Big Oil—Operating Cash Flow (Precapex)

in $ millions



Source: Company data, Credit Suisse estimates. NB: Brent price deck: $108/bbl in 2011, $105/bbl in 2012, $115/bbl in 2013, $120/bbl in 2014, $90/bbl in 2015.

Cashflow would expand even if Brent oil prices fall back to $90/bbl

Given healthy cash generation, **the question now turns to what the Majors will do with their cash flow**. As always, the choices are essentially between increasing capex (organic and external) and shareholder returns. Excess cash can accommodate higher shareholder returns at CVX and XOM in the form of buybacks and in the form of higher dividends at Shell and possibly BP. On the other hand, we think higher capex at European majors will leave little room for managements to raise dividends significantly. However, we expect managements to consolidate liquid shales if the right opportunity presents itself.

M&A will compete with distributions as a use of excess cash

In this section, we will address the majors' uses of cash in 4 categories:

M&A;

organic capex;

exploration; and

shareholder returns.

1. M&A Could Take the Lion's Share of the Excess

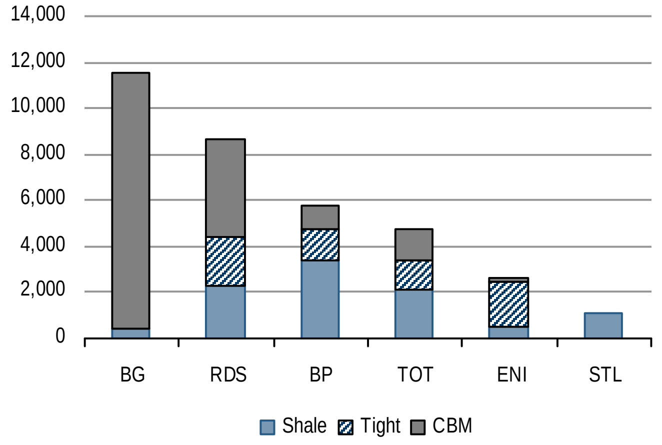
Given high oil prices and healthy cash flows, we think global oil and gas M&A and JV activity should remain high in 2012, with the majors being acquirers of assets or companies. For majors coming late to a new geological trend, M&A offers the only way to build up material exposure quickly enough. We expect the majors to be selective and to plug identified "gaps" in their portfolios, depending on their risk appetites and current exposures. Much of this activity will be within Shale (especially liquids) but East Africa gas and Offshore Exploration will also garner interest.

We Expect a Significant M&A Focus on Shale Where the Majors Are Underrepresented

There are many reasons for the majors to be interested in shale: attractive returns, ability to flex capex in good times and bad, deployment of technology to lower costs and boost recovery factors. North American shale is relevant mostly for the US majors, BP, and Shell but is not currently material for continental European majors. (See Exhibit 87 below.) Outside North America, companies have been increasing exposure to shale/tight gas plays in Argentina, China, and Europe (Poland/Ukraine), and to coal-bed methane (CBM) in Australia and Indonesia. Today, shale accounts for roughly 10% of the majors resources.

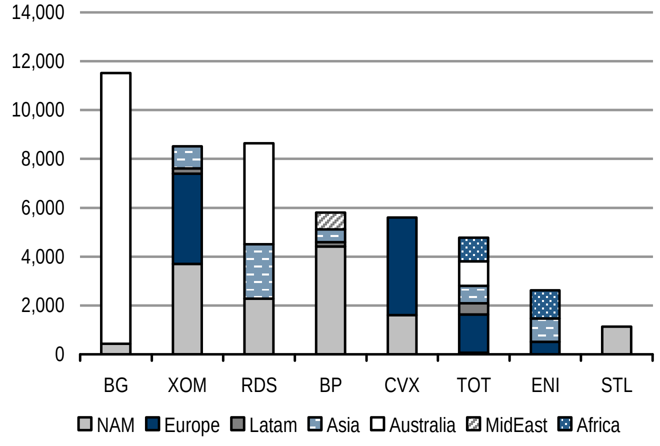
Over time, we'd expect management teams will want to increase this share through developing existing acreage and through M&A.

Exhibit 86: European Oils—Unconventional Gas by Type
in '000 acres



Source: Company data, Credit Suisse estimates, WoodMac.

Exhibit 87: Majors—Unconventional Acreage by Region
in '000 acres

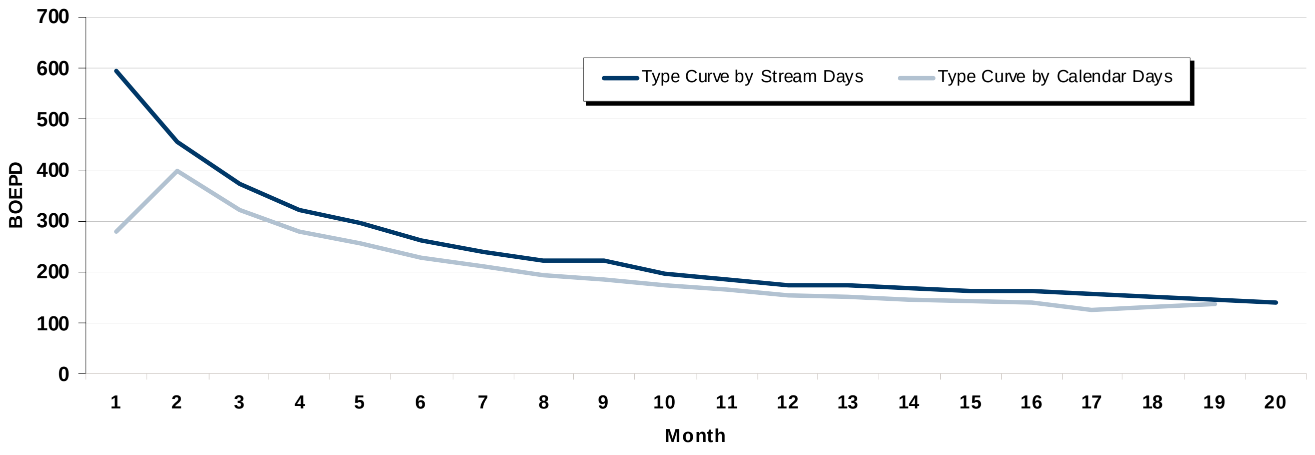


Source: Company data, Credit Suisse estimates, WoodMac.

We also believe there are several factors driving E&P's to the bargaining table, notably (1) low US natural gas prices, (2) high service costs and (3) new liquid shale plays require significant upfront capital expenditure before they contribute to free cashflow e.g. to hold leases (HBP) and to build infrastructure. It is still early days for liquid shales. There will be efficiency gains. However, today we observe that wells are not always on production and there is a wide variance in well productivity. We come to the conclusion that the well capitalized majors have a larger role to play.

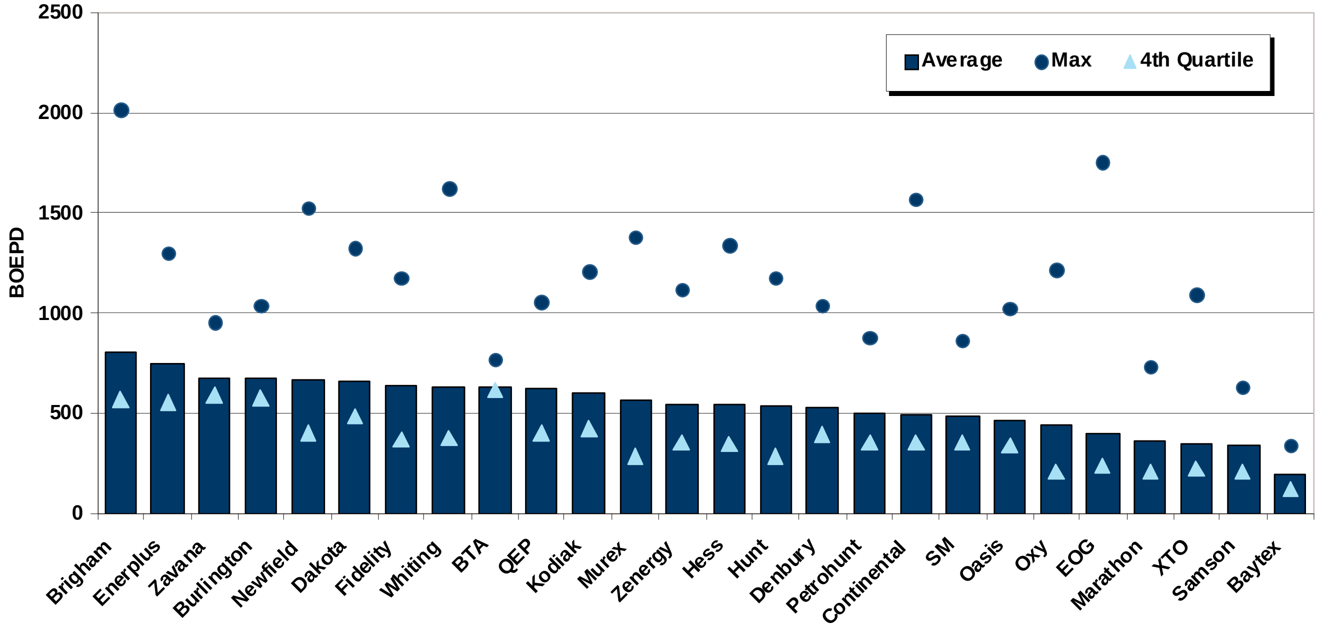
High upfront capital costs and low gas prices could drive E&P towards the Majors balance sheets

Exhibit 88: Real Life Bakken Wells Underperform the "Type Curve"



Source: Company data, Credit Suisse estimates.

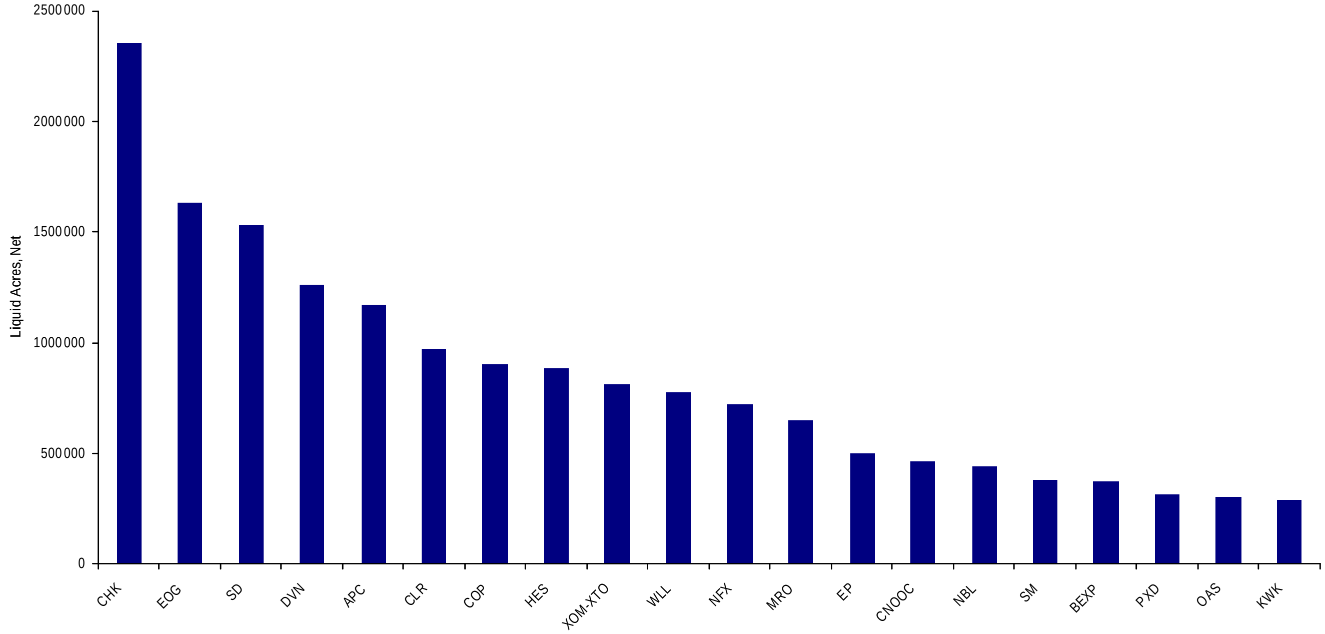
Exhibit 89: **Real Life Bakken Wells Are Quite Variable [Wells since 2010]**



Source: Company data, Credit Suisse estimates.

NAM liquids shale: The majors are underrepresented in the major liquids shale plays of North America. Although smaller companies can have a higher amount of liquids acreage per dollar of EV, questions of materiality may even attract the majors to larger deal sizes, as Anadarko and EOG are relatively well positioned. We note that Total is rumored to be Chesapeake's unnamed JV partner in the Utica; we would not be surprised if this was the case since Total has little exposure to North American shale.

Exhibit 90: **Largest US Liquids Shale Acreage Holders**



Source: Company data, Credit Suisse estimates.

NAM low-cost natural gas shale: The Marcellus (and potentially the Utica) remain the low-cost natural gas play in the US and long-term natural gas prices could settle higher than they are today, with an economic recovery, coal-fired power plant closures, and LNG exports in the long-term. We would add Deep Shelf Gulf of Mexico natural gas into this low-cost gas US M&A basket. IOCs or Asian NOCs interested in LNG exports from the US Gulf Coast or British Columbia (eg Horn River/Montney) could look to boost their shale gas acreage positions. Offsetting this cost advantage, drilling efficiency gains may cap US gas prices for some time—with the majors better represented in natural gas shales—liquids could be next on the list.

Outside the US, We Expect Consolidation of East Africa Gas and the Transform Margin

- **East Africa Gas:** We are positive on East Africa's emerging natural gas basin after large discoveries in Tanzania and Mozambique offering potential for LNG exports. In particular, we see Cove Energy as a potential acquisition target: in late 2011 the company opened up a data room for parties interested in acquiring its Rovuma Area 1 block in Mozambique. Other companies with large acreage positions (e.g. Anadarko, Ophir) could look to farm out some assets. Several European majors (BG, Eni, Statoil, Total and Shell) have some form of exposure to East Africa, but others including BP might be interested in acquiring positions.
- **Equatorial Atlantic Transform Margin:** Another area for potential consolidation or JV activity are the new geological plays along the Atlantic Basin, both in West Africa (Ghana, Liberia, Sierra Leone, Côte d'Ivoire) and across the Atlantic in the Guyana-Suriname basin.
- **Argentina Shale:** YPF's large shale oil discovery in the Vaca Muerta area has further ignited interest in this play, previously considered to be mostly gas-prone. We expect YPF to firm up the play in the next 12 months, while also looking to farm out some acreage to international majors. Of the majors, only Exxon and Total have exposure to Argentina shale, so we would not be surprised to see interest from other majors.
- **Kurdish region of Iraq:** The region's profile was raised significantly by the entry of majors e.g. Repsol, Hess and most recently Exxon. We think the Kurdish region of Iraq is attractive from an M&A perspective in the context of an industry with restricted access to resources, particularly to conventional onshore oil. According to press reports, majors including Chevron, Eni and Total may be in talks with the Kurdish Regional Government to acquire licences. Small-cap E&Ps in the region might also be of interest to larger companies. Above ground issues (politics/infrastructure) are the main constraints.
- **Brazil:** As the recent Galp/Sinopec and HRT/TNK-BP deals have demonstrated, there is continued interest in Brazilian oil & gas resources. More Brazilian assets could be coming to the market in 2012, with Anadarko seeking to exit its entire position in Brazil, which includes the Wahoo and Itaipu fields (where BP is a partner). BG is also periodically rumoured to be selling part of its Santos basin acreage to an Asian NOC.

2. Organic Capex—Shift to Long-Life Assets Continues

Summary: With a strong cash flow backdrop and high commodity prices, there is a continued requirement to sanction projects and secure growth for the second half of this decade. We expect organic capex to continue to rise for most oil majors. Non-conventional assets (LNG, oil sands) are key to Big Oil's transition to lower-decline portfolios by 2020.

Spend to rise by 7-8% in 2012

In our view, the majors are only halfway through a decade-long process of rebuilding their legacy assets. The ramp-up in investment since 2004 is starting to bear fruit, but there is still a long way to go for many companies. Eventually, cash flow will rise and capex growth will be more muted (as maintenance capex should drop), but the real inflection point in free cash flow is still quite a few years away (mid-decade) for most companies.

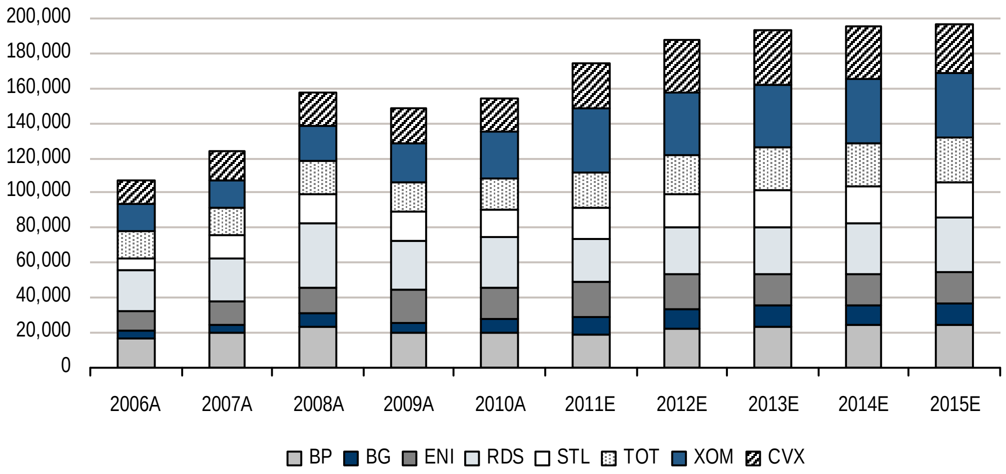
Organic capex at STL, TOT, CVX and BP still set to rise

We highlight that **there are important differences in where companies are in their cash cycle.** A broad-brush approach unfortunately does not work, as it ignores fundamental differences in the companies' strategies and cash cycles. As we have written in our research in 2011, capex at majors including Total, Statoil, BP and Chevron are set to rise strongly in the next few years. Only Shell stands alone its position of having already invested in long-life assets over the last 5-6 years (in projects such as Pearl GTL etc), leaving the company in a structurally better position than its peers until the latter eventually catch up.

Capex Cycle Continues—Spend to Rise by 7-8% in 2012

Using our database of the largest Big Oil projects, we can already get a handle on capex budgets in the medium term. Group capex should rise by 7-8% y/y in 2012 to $214bn, followed by (potentially) slower increases thereafter. We expect to see the largest increases at CVX, Total, BP and Statoil (between 10% and 15% y/y), and smaller increases at Shell, Eni and XOM (flat y/y to +6%).

Exhibit 91: **Big Oil—Capex to Hit New Record Highs in 2012, and Keep Rising**
in $ millions

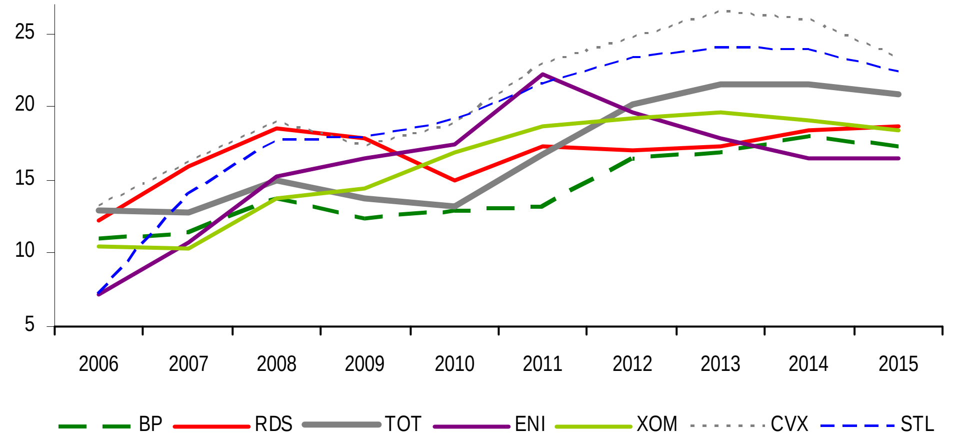


Source: Company data, Credit Suisse estimates.

As Exhibit 92 below shows, Big Oil's capital intensity per barrel is still set to rise. On our estimates, upstream capex per barrel produced is set to average to almost $20/bbl over 2011-15, significantly higher than the $14/bbl unit capex in the preceding 5-year period.

The majors development spend on long lived assets has pushed capital intensity higher by 50% versus 2006-2010

Exhibit 92: Big Oil's Upstream Capital Intensity Is Still Rising
Upstream capex per barrel produced, in $/bbl



Source: Company data, Credit Suisse estimates. NB: BP excludes TNK-BP.

Shift to Long-Life Assets Continues

Capex will eventually lead to a payoff

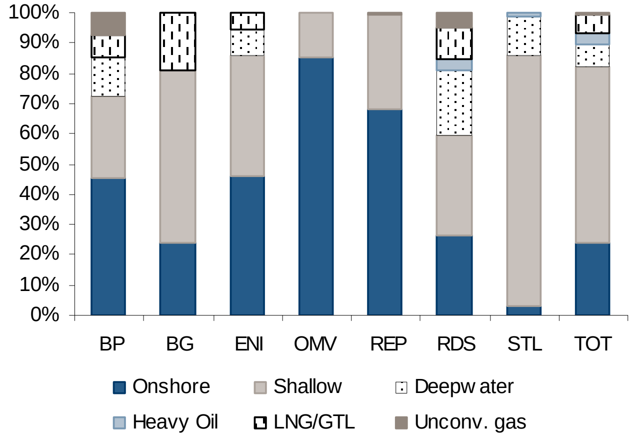
The composition of capex over the next 4 years will shift toward more nonconventional, long-life assets such as LNG and oil sands. The share of deepwater projects will also continue to rise, while the proportion of conventional oil & gas (onshore and shallow water) projects will drop further as these opportunities become more scarce.

On our estimates, deepwater, LNG and oil sands together should represent 58% of European majors' upstream growth capex (ex-maintenance) in 2012, up from less than half in recent years. Conventional projects still make up c.35% of growth capex, down from almost 50% in the mid-2000's. Deepwater, LNG and oil sands projects tend to be more capital-intensive than conventional projects (hence the sector's rising capex needs), but will also generate higher cash margins per barrel once they are onstream.

In production terms, long-life assets (LNG, oil sands) will represent 14% of European oils' total production in 2015E, up from 8% in 2005. When adding nonconventional gas (which offers large resources but needs continued investment), the share of low-decline assets will rise to almost 20% by 2015E, up from 17% in 2011E. In Europe, Shell and BG have the largest proportion of non-conventional assets in their portfolios, followed by Total and BP. XOM and CVX lead in the US.

Exhibit 93: European Oils—2005 Production Breakdown

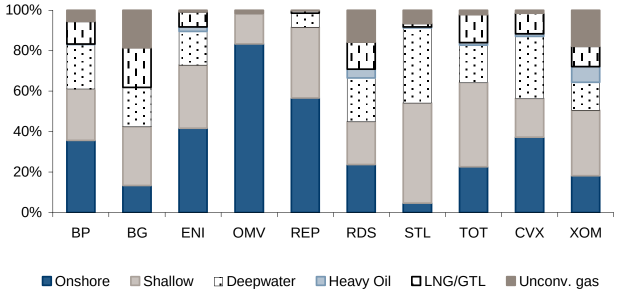
in % of total upstream volumes



Source: Company data, Credit Suisse estimates.

Exhibit 94: Majors—2015E Production Breakdown

in % of total upstream volumes



Source: Company data, Credit Suisse estimates.

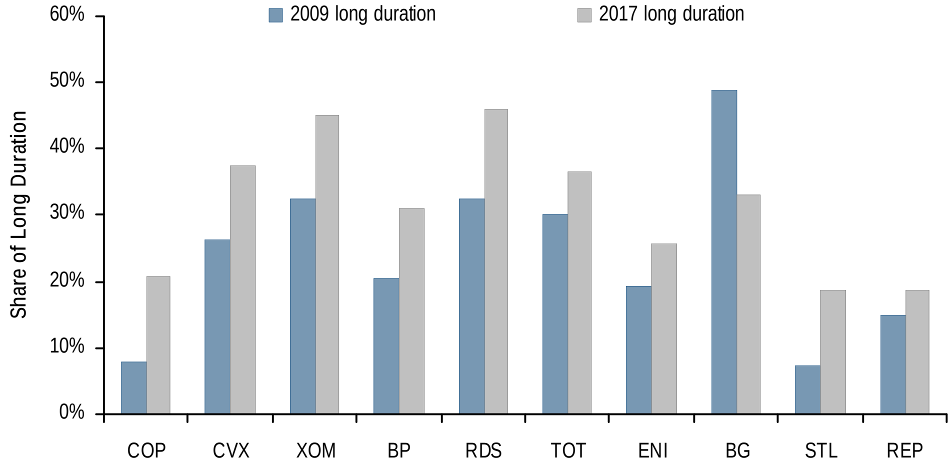
There Will Eventually Be a Payoff from This Capex

In our view, investing in low-decline unconventional OECD assets is a big part of the solution for the oil majors battling against natural field declines. Indeed, long-life OECD assets appear to offer Big Oil the answer to many of their problems: Canadian oil sands and Australian LNG projects for instance provide (a) low-decline volumes, (b) strong cash flows with little associated maintenance capex, and (c) more stable fiscal regimes than in the non-OECD, at least in theory.

No one embodies this strategy better than Total, which has put on hold its riskier Nigerian deepwater and gas projects, and thrown itself in the pursuit of nonconventional assets, many of which are in the OECD (e.g., Barnett shale gas, Ichthys and Gladstone LNG in Australia, Joslyn and Fort Hills in Canada). Chevron is pursuing a similar strategy on the LNG side, with huge investment going into two LNG mega-projects in Australia ($43bn into Gorgon and $29bn into Wheatstone). Shell is just ending a program of heavy investment in Gas-to-Liquids and LNG in Qatar, but still continues to invest in low-decline assets such as LNG (Gorgon, Prelude, Pluto, possibly Arrow, Sunrise, Abadi and British Columbia) and Canadian oil sands (further expansions at AOSP).

The upside of having large share of low-decline assets is reduced maintenance capex requirements once the projects are onstream. By 2017, we estimate that long-life assets will represent c.45% of volumes at XOM and Shell, and close to 40% at CVX and Total.

Exhibit 95: Big Oil—Duration Is Rising, Reducing Long-Term Maintenance Capex Needs
Long life assets in % of total upstream production



Source: Company data, Credit Suisse estimates. N.B.: "Long duration" includes LNG, GTL, oil sands, non-conventional gas and low-decline conventional oil & gas.

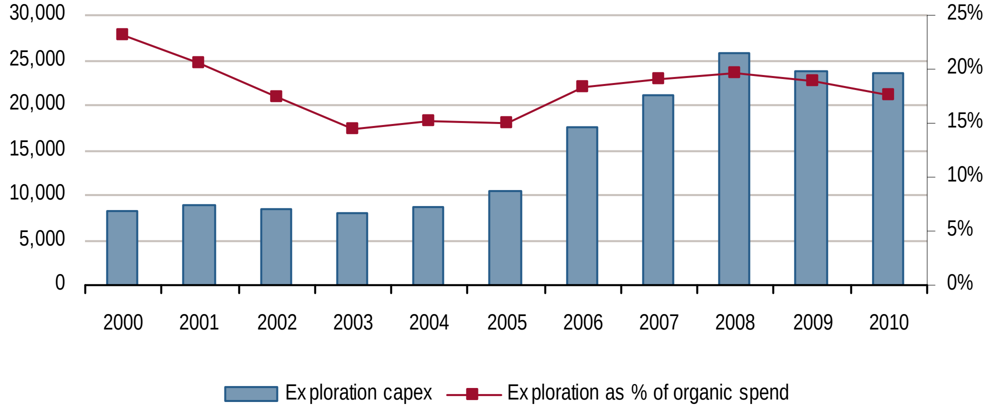
As long-lived projects become a higher share of the production mix, maintenance capital burden should lessen

3. Exploration

Exploration spend has been rising in recent years as higher oil prices encouraged Big Oil to refocus on finding hydrocarbons through the drill-bit, and we expect this trend to continue. The rationale is simple: exploration, particularly in the offshore, is often a route to higher investment returns. We estimate average IRRs on deepwater projects in the mid-20s, compared with the low teens for more capital-intensive, long-life projects such as LNG and oil sands (though the latter have other attractions). Exploration capex currently makes up only 18% of organic upstream spend—well below the proportion spent by independent E&Ps—so we believe there is still room for Big Oil to increase its exploration budgets.

Although organic exploration spend has increased, doubling since 2005, M&A will continue to play an important role to drive resource growth

Exhibit 96: Exploration Capex, 2000-10A
in $ millions, and as % of total upstream organic spend



Source: Company data.

4. Higher Dividends/Buybacks for Some

Healthy cash flow should leave room to increase shareholder returns in the form of dividends or buybacks, for some select companies. However, we believe management teams are keeping cash on the books as an insurance against economic risk but also as a strategic fund for M&A opportunities.

Shell, BP and Repsol could raise dividends; we believe the US majors would rather use buybacks to maintain strategic flexibility

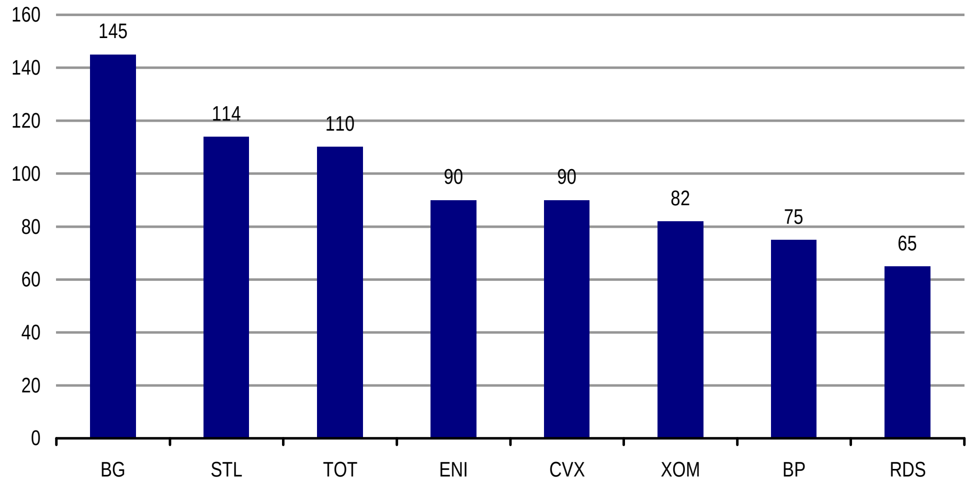
We note that M&A will remain a key alternative to higher dividend distributions

The SuperMajors Needs $85/bbl to Cover Dividends in 2012

Given the prevailing triple-digit oil price environment, it is perhaps unsurprising that Big Oil managements are comfortable raising their capex budgets so aggressively. In effect, a lack of organic production growth in 2011 (-4% y/y) has been more than compensated by higher oil prices, allowing management teams to raise spending.

Taking a closer look, it appears that **the sector's average free cash breakeven (post capex, post dividends) of the SuperMajors is around $85/bbl in 2012**, higher than in previous years. There is a wide range of Free Cash breakevens, between $65/bbl in the best case (Shell) to over $110/bbl in the worst case (Total, Statoil), and up to $145/bbl for the big spenders like BG. Even US supermajors XOM and CVX break even at $82-90/bbl, as both have ramped up their capex programs in recent years.

Exhibit 97: **Big Oil free Cash Flow Breakeven (Post Capex, Post Dividends)**
in $/bbl



Source: Company data, Credit Suisse estimates. NB: BP breakeven excludes potential Macondo payments.

We have sympathy with fast-growing companies like BG (which offers c.8% p.a. production growth), as we understand their need to run large funding deficits to invest for future growth. However, we find it mildly worrying that large-cap integrateds such as Total and Statoil cannot self-finance their capex and dividends at anything less than $110/bbl.

Of the Europeans, we believe Shell, BP and Repsol should be in a position to raise dividends in 2012. For **Shell**, a strong increase in underlying cash flow driven by its Qatar mega-projects should push up its free cash flow by a third to c.$19bn in 2012 vs a current dividend of c.$10bn. We expect Shell to raise its dividend by 8% in 2012, putting it on a competitive yield of over 5%. For **BP**, we believe greater confidence on the outcome of the Macondo trial and in the possibility of a settlement can lead to a dividend increase. On our estimates, BP should generate c.$12bn of post-capex, pre-dividends free cash flow in 2012, vs a current dividend of c.$5bn and $10bn before Macondo. We do not expect BP to return to pre-Macondo payout levels, but believe BP can afford to increase its dividend by up to 30% in 2012 to $0.36/share, implying a c.5.2% dividend yield on a par with Shell.

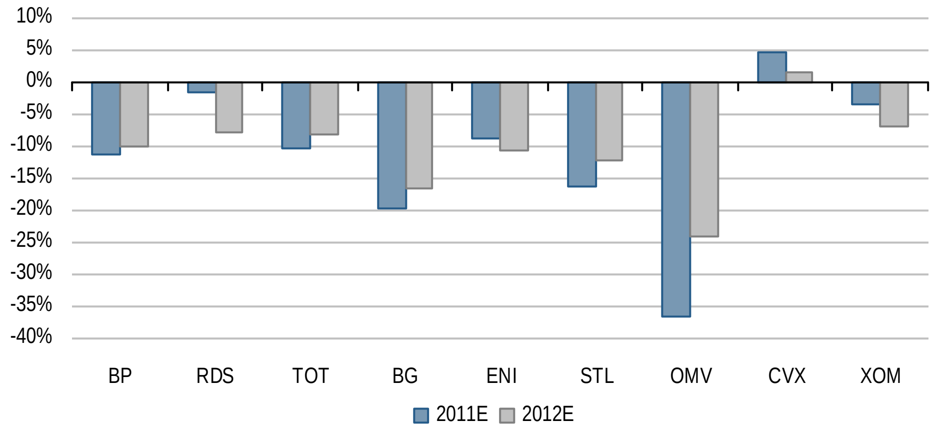
We do not expect other majors including Total, Eni and Statoil to raise their dividends in a meaningful way given declining free cash flow at Total and Statoil, and Libyan uncertainty at Eni. In the US, Exxon and Chevron will deliver dividend growth but we would expect buybacks to be preferred for excess cash, leaving more flexibility for M&A.

Integrated Oils—Operating Outlook

Despite delivering strong CFPS growth overall in 2011, EPS for the big-cap European and US majors looks set to be c.8% below our estimates published in March 2011 ("*Integrateds at Triple Digit Oil*", 17 March 2011). As Exhibit 98 below shows, only CVX managed to surpass our estimates this year. The smallest shortfalls vs. our expectations have been at Shell, XOM, and Eni (2% to 9% below our estimates), and the biggest disappointments were seen at BG, Statoil, BP, and OMV (11% to 36% below). With 2011 behind us, in this section, we address the 2012 outlook for the Integrated Oils, looking more specifically at 3 themes: (1) upstream volume growth, (2) refining and (3) LNG / gas.

European volumes to bounce back in 2012, but we have concerns over European downstream profitability

Exhibit 98: Change in Credit Suisse 2011-12E Estimates, Dec 2011 vs. March 2011
in %



Source: Company data, Credit Suisse estimates.

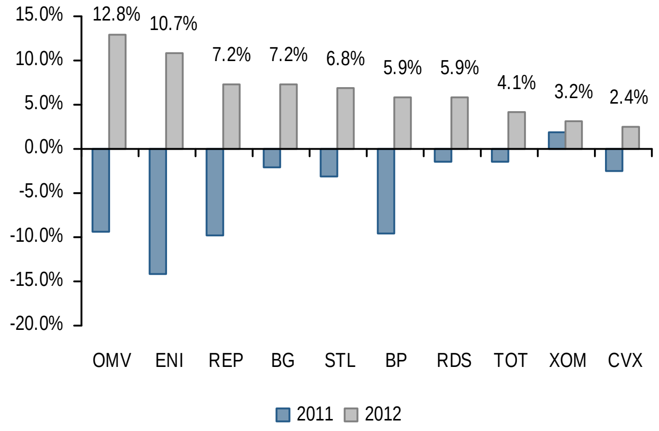
Upstream Production Growth Set to Rebound

While the market is becoming more aware that production growth does not capture the whole story (cash flow growth is more important), volume growth remains an important metric for many investors. We see 2012 production growth in isolation as somewhat meaningless for stock comparison purposes, since 2011 was hit by many unpredictable issues (Libyan civil war, unplanned downtime in North Sea and elsewhere, GoM moratorium), some of which will reverse in 2012. Accordingly, European majors—which were disproportionately hit in 2011—should grow faster than US majors as volumes lost in 2011 should return.

With these caveats in mind, we see production growth of just under 5% in 2012 for the group, on paper. Although we see **Eni** and **OMV** leading the pack in 2012 in terms of production growth with 13% and 9% y/y growth respectively, this increase on 2011 can be largely accounted for with Libyan production coming back on stream rather than through organic growth. After 3 consecutive years of disappointments, **BG** should see a return to strong growth (c.7% y/y) in 2012 with Egypt, Bongkot (Thailand) and Jasmine (UK) development as well as the ramp-up of the Lula pilot FPSO in Brazil's Santos Basin. We expect **BP** to grow by c.6% owing to their return to the Gulf of Mexico and a decrease in scheduled maintenance. **Total** and **Shell** see 4% and 6% growth respectively in 2012 with Pazflor expected to ramp up earnings for Total and Pearl GTL reaching full capacity by mid-2012 for Shell. **Exxon**'s production growth remains weak looking into 2012 but 2013 will see an improvement with liquid volumes growing (Kearl) and growth from their global low-cost natural gas reserves.

Exhibit 99: Upstream Volume Growth, 2011-12

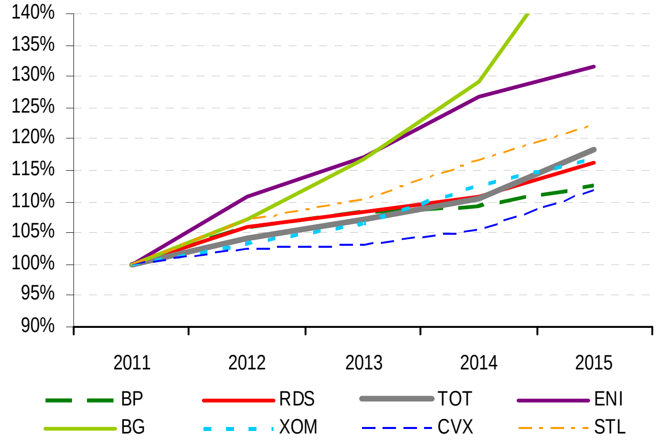
in %, y/y



Source: Company data, Credit Suisse estimates.

Exhibit 100: Upstream Volume Growth, 2011-15

Rebased in 2011 at 100



Source: Company data, Credit Suisse estimates.

Downstream Headwinds in 2012, Especially in Europe

2011 saw a very challenging downstream environment in Europe, and we see no respite in 2012. It seems the sector is headed for a bleak start to 2012 as Europe's poor economic performance and unseasonably warm weather eat into middle distillates demand. We expect OECD oil demand to move sideways in 2012, but there could be downside to our estimates if Europe's financial crisis deepens further.

Although upstream volumes are superior in Europe, downstream headwinds could constrain CFPS growth overall

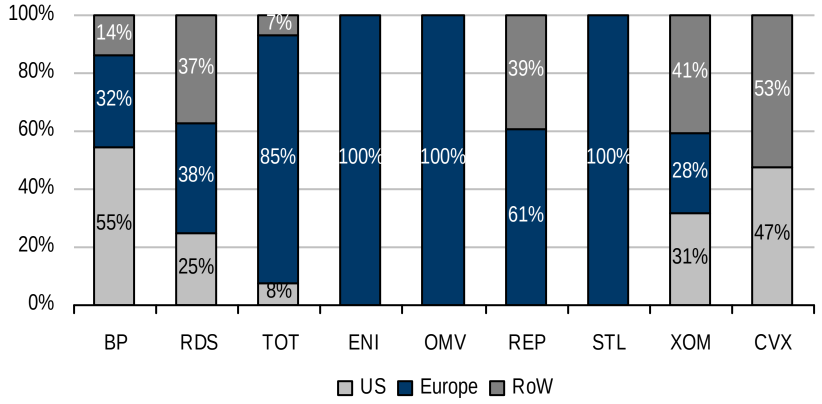
Weak end-demand in the OECD should keep run rates low, especially in Europe (current utilization is at c.80%), unless rationalization accelerates. We have seen some welcome plant closures recently with the idling of 360kbd of capacity on the US East Coast (PADD 1)—unfortunately expansions in the US (e.g., Motiva's Port Arthur) and the start-up of more complex plants in the non-OECD will add to global refinery overcapacity in 2012. Meanwhile, **rationalization in Europe is not happening fast enough** owing to resistance from governments/labor unions, leading to a stubbornly high excess capacity of over 1mbd.

Rising risks around **crude oil supply disruptions** (Iran, Venezuela, Russia) are creating additional worries for refiners, especially in Europe which already had to dealt with the loss of light sweet Libyan crude in 2011. Libyan volumes appear to be ramping up faster-than-expected, with the country's oil minister stating that output had reached 1mbd in mid-December 2011 (vs. 1.6mbd before the war), however, we remain cautious on how quickly exports (now at >400kbd) can reach prewar levels given damage to export infrastructure and political tensions.

Company exposure: Assuming refining margins remain weak, then the companies that are most exposed to European R&M (relative to their earnings base) include OMV, Repsol, Total and Eni. Exxon, BP and Shell have less *relative* exposure to European downstream, but their US refining profits should fall in 2012 vs 2011 owing to the narrowing of the WTI-Brent spread following the announcement of the Seaway pipeline reversal. CVX delivered a record 2011 in downstream despite its limited WTI-Brent exposure, indicating less downside to its earnings.

Exhibit 101: Integrated Oils—Downstream Exposure by Geography (2010A)

in % of total refining capacity



Source: Company data.

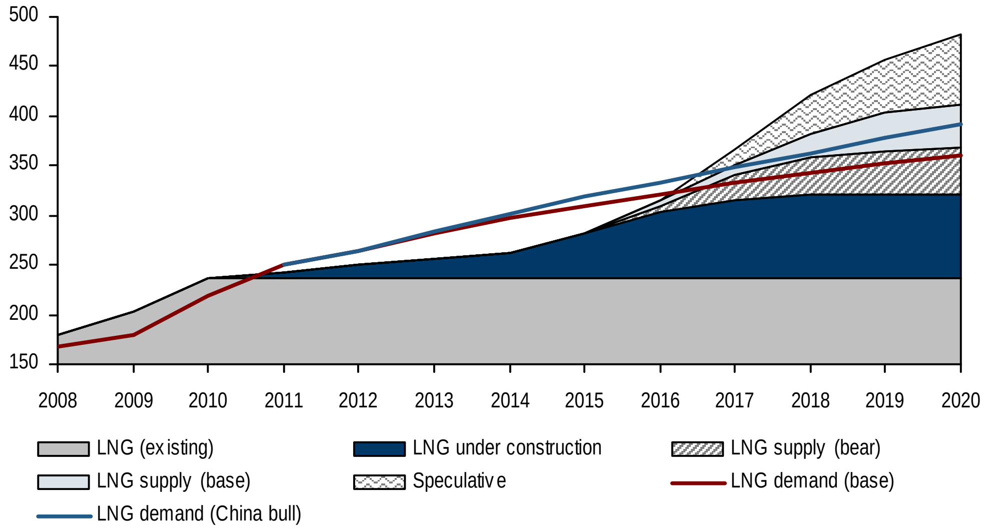
We also see **risks to petrochemical earnings in Europe** if demand remains weak. European petchem margins have been steadily narrowing in recent months, due to still high naphtha (oil-based) feedstock costs and a weakening demand environment, also putting pressure on volumes. Companies most exposed to European chemicals (relative to their earnings base) are Total and Eni. BP and Shell also have exposure, but Europe-based petchems represents 1/3 or less of capacity vs 2/3 or more for Total and Eni.

Asia-Pacific LNG Market Tightening in 2012

Tight LNG markets should help BG, RDS, and TOT

We forecast that the global LNG market will get tighter in 2012, with tightness concentrated mostly in the Asia-Pacific region. This view is largely driven by the lack of large LNG plant start-ups, the mothballing of nuclear power capacity in Japan and Germany, and strong demand growth in Asia-Pacific. On the supply side, with the Qatari ramp-up now behind us, we expect only 7.2mtpa of LNG capacity additions in 2012 (from Pluto T1 and Angola LNG), which should be more than offset by demand growth in Asia-Pacific and Europe.

Exhibit 102: Global LNG Demand vs. Potential Supply (in mpta)



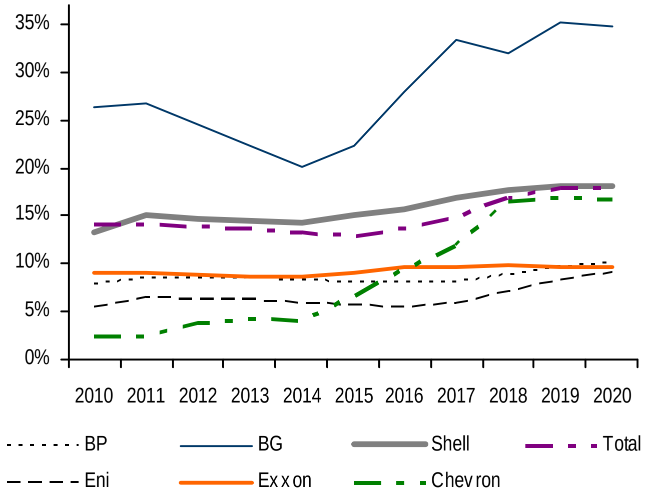
Source: Company data, Credit Suisse estimates.

NB: China bull demand case assumes that 30% of additional gas demand is met by LNG.

We hold the view that **BG** is well-placed to benefit from tightening in the LNG market, with its flexible LNG volumes (e.g., from Equatorial Guinea, Egypt, and Nigeria) and strong trading capabilities allowing it to benefit from arbitrage opportunities. To a lesser extent, we believe that **Shell** will be able to benefit from a tighter market given its position in Sakhalin II and Malaysia LNG, and flexible volumes from Qatargas 4 (which has been operating at plateau since 2Q11). **Total** should also be well-placed given its position in Bontang, Yemen and Nigeria LNG.

Exhibit 103: **BG, Shell, and Total Have Largest LNG Exposure**

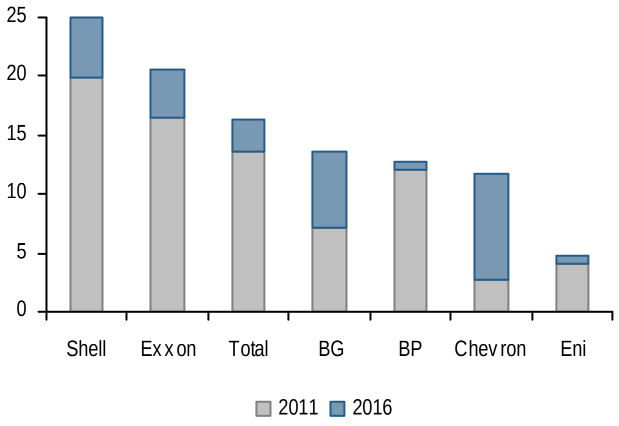
Equity LNG as % of total upstream production



Source: Company data, Credit Suisse estimates.

Exhibit 104: **Global Majors LNG Capacity, 2011 vs. 2016E**

in mtpa of equity LNG capacity



Source: Company data, Credit Suisse estimates. NB: Downstream LNG exposure.

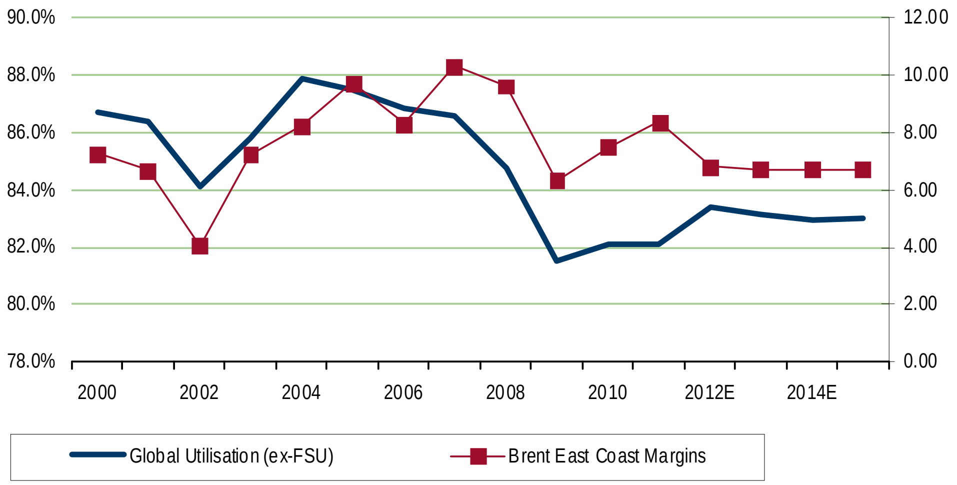
On the other hand, we see downside risks to North Sea gas volumes in early 2012. Given weak gas demand and warmer temperatures, we believe European consumers will continue to minimise offtake of expensive oil-linked gas under take-or-pay agreements, and favor cheaper spot gas (including spot-linked LNG) instead. In our view, this presents downside volume risks to exporters of more expensive oil-linked piped gas from the North Sea, primarily Statoil (North Sea gas is 38% of total upstream volumes). Other majors exposed to North Sea gas production include Shell, Exxon, Total and Eni (12-18% of total volumes), but downside risks to volumes for them should limited as their gas tends to be priced off spot-linked than oil-linked.

Global Refining in 2012—Difficult Outside the US

3MBD of closures or higher demand would be required for margins to gain ground

2012 is likely to remain as difficult for nonadvantaged refiners as 2011. Although Libya should bring more light sweet crude back into the market, end-user demand in the OECD remains weak and we cannot rule out other light sweet crude supply disruptions (e.g., Nigeria). In the oil commodity section, we lay out various scenarios for global demand. Although we remain of the view that oil demand will remain positive, driven by the non-OECD, we don't believe global utilization will rise sufficiently to stress refining markets without further closure. Complex US refiners with access to low cost crude can still make decent money even within this outlook but for the remainder, survival is the most important decision making driver.

Exhibit 105: Global Utilization—More Closures Required



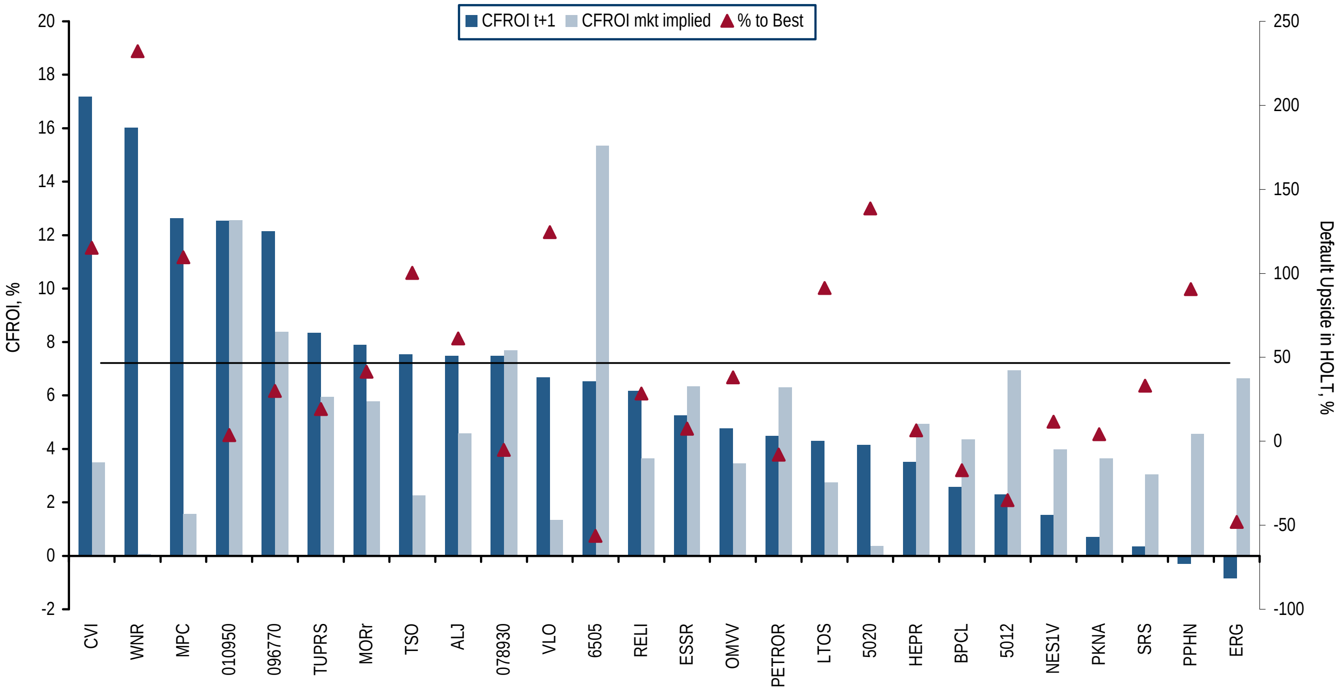
Source: Company data, Credit Suisse estimates.

A Decade of Free Cashflow for the US; Restructuring Elsewhere in the OECD

Competitive advantages underpin strong free cashflow at the US refiners even with global oversupply

We believe that the US refiners ability to process cheap heavy crudes and access to lower cost North America domestic production of light sweet and Canadian heavy crudes will underpin a decade of free cashflow even with lackluster gasoline demand in the US. However the market is clearly not paying for it. The US refiners generate substantially higher returns and yet discount more pessimism even than challenged European refiners and despite relative outperformance in 2011. The US refiners remain for us a deeply undervalued group generating substantial free cashflow and increasingly management teams are sharing this cashflow with investors through higher dividends.

Exhibit 106: Global Refiners through the HOLT Lens—Profitability, Embedded Returns, and Potential



Source: Credit Suisse HOLT.

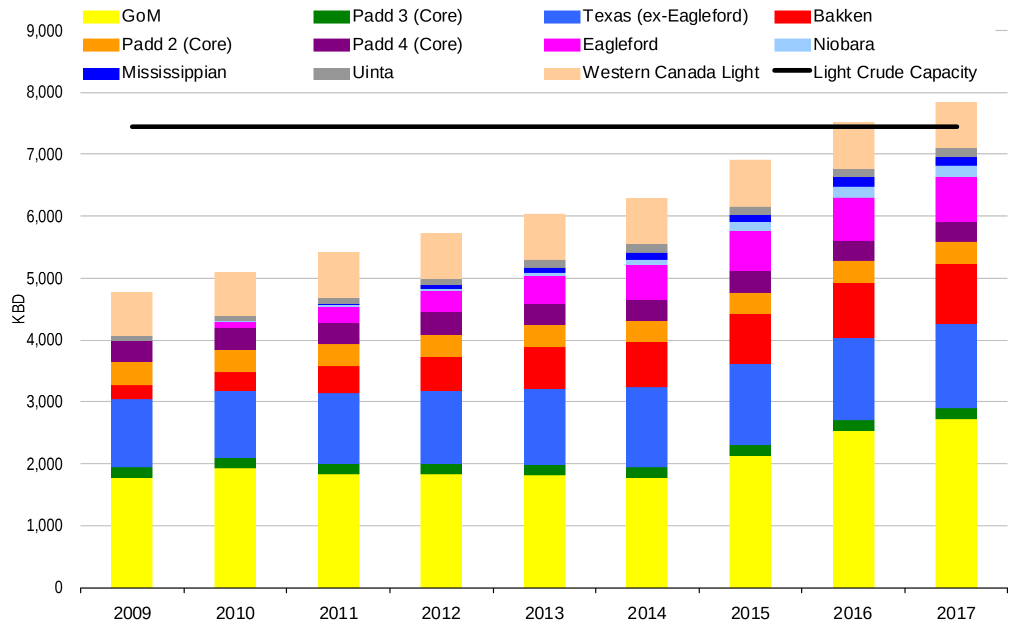
Advantaged Crude Logistics, High Complexity and Cheap Natural Gas Underpin Strong Free Cash Generations

Assuming oil prices remain robust enough to drive shale development and that Seaway/Wrangler/Keystone XL (eventually) brings heavy Canadian crude oil to the Gulf, we believe there is a chance the whole region becomes over-supplied with light crude causing LLS to widen versus Brent. This is important as global product prices tend to move together. As WTI and LLS crudes remain cheaper than Brent, US Mid Con AND Gulf Coast refiners could generate higher midcycle earnings than they did in the past.

In the following analysis, we assumed Gulf Coast and Mid-Con refiners would fill up their cokers first with heavy crude. We then looked at the production of Mid-Con and Gulf crudes against the available capacity to process these crudes. Ultimate crude disposition will depend on different refinery configurations, i.e., a more sophisticated analysis than our simple approach. Nevertheless our analysis suggests there could be a surplus of light sweet crude in the Gulf+Mid Con regions by 2016. We don’t expect additional refineries to be built to take advantage of this surplus. Rather we expect LLS prices will fall vs. Brent and this could lead to higher LLS Gulf Coast margins over time, a potential upside for US refiners.

The US refiner trades on an average mid-cycle free cash flow yield of 17%, with longer term cyclical upside potential, if enough additional refineries outside the US are closed quickly enough

Exhibit 107: As US Domestic Light Sweet Crude Capacity Grows It Could Drive LLS to A Discount



Source: Company data, Credit Suisse estimates.

Exhibit 108: Free Cash Flow Yield, US Refiners

	FCF Yields - Enterprise Value				
Company	**2011**	**2012**	**2013**	**2014**	**2015**
DK	11.2%	10.3%	15.4%	11.4%	18.7%
CVI	11.9%	15.3%	19.7%	20.9%	17.2%
HFC	22.8%	11.3%	10.9%	13.2%	15.9%
MPC	17.7%	13.4%	18.0%	19.8%	24.7%
TSO	16.6%	1.7%	7.7%	14.7%	16.9%
VLO	2.1%	4.8%	13.3%	17.3%	21.9%
WNR	17.4%	21.7%	20.0%	13.8%	20.9%
AVG	**11.7%**	**9.0%**	**14.4%**	**17.1%**	**21.3%**

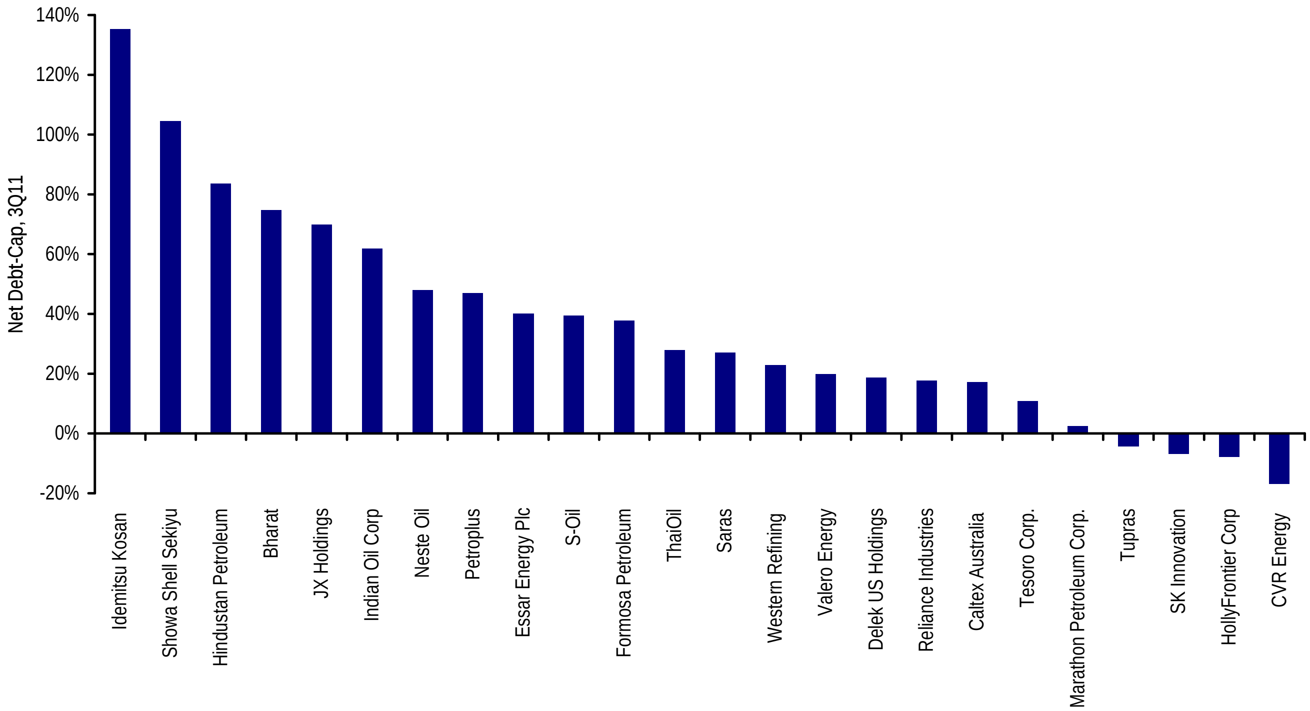
Source: Company data, Credit Suisse estimates.

A Survival Game Elsewhere in the OECD

Outside the US, refining profitability remains weak and is likely to remain so through 2012. In a downside case for the European economy, stretched balance sheets at international refiners could become even more challenged. We think Euro refiners will continue to struggle in 2012. The operating economics have worsened sharply in 2011, and we expect this to remain challenging in 2012. The major challenges in Europe include declining regional demand, stricter regulations, and the need to consolidate operations against a backdrop of stiff resistance from governments/labor unions, while competing against new and more competitive players elsewhere. Particularly, the independent, simple refiners will struggle as Bigger Oils find it harder to rationalize.

The US Refiners have also got a better balance sheet than global peers

Exhibit 109: Net Debt-Total Cap, Q311

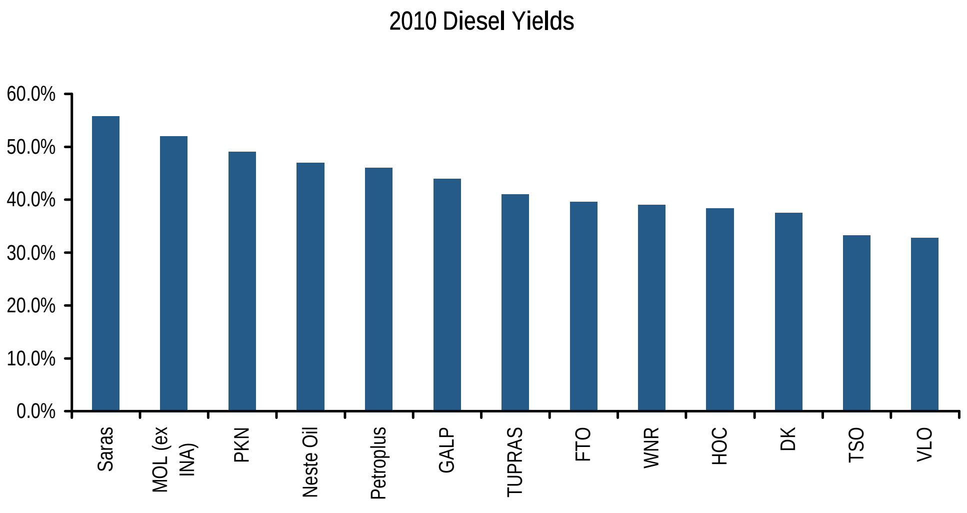


Source: Company data, Credit Suisse estimates.

The saving grace, particularly of the more complex European refiners, could be a relatively high diesel yield, given that this is the fastest growing product worldwide and that refining margins for diesel remain strong.

The one saving grace for complex European refiners could be the diesel yield, the strongest part of the demand barrel

Exhibit 110: Diesel Yields by Refiner



Source: Company data, Credit Suisse estimates.

More Closures Required

We track around 3 million barrels of refining capacity closures since the beginning of the "Great Recession." These are predominantly in the OECD and predominantly of lower complexity and smaller-scale assets (100kbd capacity).

Exhibit 111: Announced Refining Closures and Potential at Risk Refineries

Announced closures	Region	Country	Company	Capacity (kbbld)	Complexity	Status
Quiangquao	Asia-Pacific	China	PetroChina	50		Shutdown completed in June 2009
Negishi	Asia-Pacific	Japan	JX Holdings	70	9.1	Cutting capacity of 70kbd out of 340kbd by October 2010 (from March 2011)
Oita	Asia-Pacific	Japan	JX Holdings	24	6.6	Cutting 24kbd out of 160kbd by May 2010 (from March 2011)
Kashima	Asia-Pacific	Japan	JX Holdings	21	6.4	Cutting 21kbd out of 210kbd by May 2010 (from March 2011)
Mizushima	Asia-Pacific	Japan	JX Holdings	110	13.7	Cutting 110kbd out of 455kbd. Streamlining refinery at Mizushima by June '10
Toyama	Asia-Pacific	Japan	JX Holdings	60	1.8	Closed in 2009
Various refineries	Asia-Pacific	Japan	Cosmo Oil	80	8.6	Cut 100kbd at 3 refineries, and increased 20kbd at 1 refinery. Completed in Feb 2010
Ogimachi	Asia-Pacific	Japan	Showa Shell	120	7.9	Closed in Sept 2011
Sodegaura	Asia-Pacific	Japan	Fuji Oil	52	8.2	permanent closure of crude unit 1 in Nov 2010 (from 192kbd)
Tokuyama (Yamaguchi)	Asia-Pacific	Japan	Idemitsu Kosan	120	6.9	permanently closed by March 2014
tbc	Asia-Pacific	Japan	JX Holdings	200		Looking to cut another 200kbd by March 2014
Clyde	Asia-Pacific	Australia	Shell	85	7.7	to be converted by mid 2013
Eagle Point	North America	US	Sunoco	145	8.4	Permanently shutdown and dismantled in late 2009
Bloomfield	North America	US	Western Refining	17	6.3	Shut down as part of refinery restructuring
Montreal East	North America	Canada	Shell	130	9.4	Operated as terminal since last 2010
Yorktown	North America	US	Western Refining	70	8.4	Shut down - Now operated as a terminal
Bakersfield	North America	US	Flying J	68	8.8	Alon to reopen secondary units at refinery by the end of 2011 - No CDU
Tulsa	North America	US	Holly Corp	40		Merger of 2 refineries - Reduced capacity for optimal performance
St Croix	North America	Virgin Islands	Hovensa	150	9.4	Capacity reduction to 350kbd by 1Q11 (announced Jan 2011)
Trainer	North America	US	Conoco	185	8.0	Idled in Oct/Nov 2011
Marcus Hook	North America	US	Sunoco	175	8.2	Idled in Nov 2011
Gonfreville	EMEA	France	Total	80	7.8	Cutting capacity by 80kbd from 339kbd
Teesside	EMEA	UK	Petroplus	117	2.1	Announced in 2009, and converted in 2010
Dunkirk	EMEA	France	Total	137	6.7	Long-term shutdown since Sept 09. Converted in 1H10.
Harburg	EMEA	Germany	Shell	107	9.6	To be converted by early 2012
Reichstett	EMEA	France	Petroplus	85	5.3	Petroplus looking to convert in 1Q/2Q11
Cremona	EMEA	Italy	Tamoil	94	7.6	To be converted by end 2011
Wilhelmshaven	EMEA	Germany	Conoco	260	5.2	we treat this as inoperable refinery despite the sale (instead used as midstream)
Arpechim	EMEA	Romania	Petrom	70	7.3	Converting to terminal in 2Q11
Berre	EMEA	France	Lyondell	105	6.7	Lyondell announced looking to sell; loss making refinery
Total				**3027**	**6.8**	

Returned capacity	Region	Country	Company	Capacity (kbbld)	Complexity	Status
Delaware City	North America	US	Valero	-210	13.2	PBF to reopen in May 2011 after Valero shutdown in Nov '09
Aruba	North America	US	Valero	-235	8.0	Resolved tax issues - Valero has restarted early 2011
Total				**-445**	**10.5**	
Net Aggregate				**2582**		

At-risk capacity	Region	Country	Company	Capacity (kbbld)	Complexity	Status
Pardubice (Paramo)	EMEA	Czech Rep	Unipetrol	20	3.9	considering ending crude refining
Fredericia	EMEA	Denmark	Shell	68	5.7	we view as potential closure candidate
Hamburg	EMEA	Germany	Tamoil	78	6.1	we view as potential closure candidate
Petit Couronne	EMEA	France	Petroplus	162	7.3	Loss making refinery; currently restructured to make more profitable
Whitegate	EMEA	Ireland	Conoco	71	5.1	Sales candidate since 2008; more likely to be converted
Rome (Pantano)	EMEA	Italy	Total/ERG	89	7.3	Sales candidate; high risk closure candidate; announcement expected in 2011
Gela	EMEA	Italy	Eni	105	13.2	we view as potential closure candidate
Livorno	EMEA	Italy	Eni	84	12.6	Klesch pulled out of bid; good infrastructure, refinery not ideal
Porto Marghera	EMEA	Italy	Eni	80	6.8	we view as potential closure candidate
Busalla	EMEA	Italy	Iplom	40	3.7	we view as potential closure candidate
La Spezia	EMEA	Italy	Arcola	33	1.0	we view as potential closure candidate
Skopje	EMEA	Macedonia	Hellenic	50	4.5	we view as potential closure candidate
Slagen	EMEA	Norway	Exxon	116	3.8	we view as potential closure candidate
Milford Haven	EMEA	UK	Murco Petroleum	106	10.3	Murphy looking to exist downstream business (announced in July 2010)
Lisichansk	EMEA	Ukraine	TNK-BP	175	8.3	Loss making without import tariffs; reviewing options
Hawaii (Kapolei)	North America	US	Tesoro	94	4.6	Evaluating future of refinery
St Croix	North America	US	HESS/PDVSA	350	10.5	Loss Making Due to High crude costs
Philadelphia	North America	US	Sunoco	330	7.7	Sales targeted, but would idle otherwise by July 2012
PADD III	North America	US	Various	664	na	At-risk refining capacity - MRO estimates
Total				**2715**	**7.9**	
Total likely closures (ex returning capacity)				**5297**	**7.9**	

Source: Company data, Credit Suisse estimates.

87% Utilization Is the Sweet Spot

In our base case, we don't expect global refining utilization to hit the sweet spot. As a reminder, when capacity utilization exceeds around 87%, dislocations caused by the lack of upgrading outside the US can lead to very attractive margins for complex refiners. Several factors could lead to an upcycle, option value for US refiner shareholders that look cheap even on midcycle earnings. Effectively, we need around 3.4 MBD of incremental supply closure or demand surprise.

1) A Non-OECD surprise: While the outlook for OECD demand remains lack-luster, our non-OECD forecast of around 3.5% pa could prove too low depending on policy aims, particularly in China/India and the penetration of natural gas in the Asia region.

2) Greater rationalization through 2012: We highlight around 2.7MBD of additional at-risk capacity, of which 2.2MBD is outside the US. US closures are probably less likely due to the energy cost advantage of cheap natural gas.

3) Deterioration of Existing Capacity: Gulf Coast refiners in 2011 have benefited from downtime at refineries in Venezuela and Mexico. Perhaps, the 2.8MBD of capacity in this region is overstated. Although this is likely the case and could add to say 600kbd of rationalization not captured in our forecasts, strong investment in the Russian refining sector will probably provide enough of a counterbalance.

We're left with the conclusion that more rationalization looks inevitable.

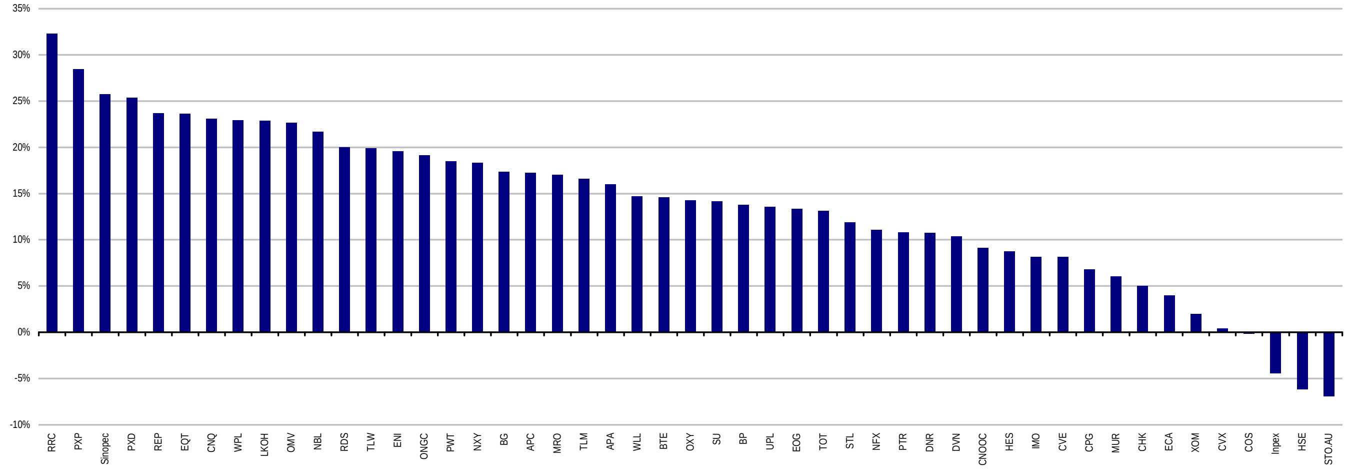
Revisiting Conversion for E&P

Conversion favors companies that can grow cashflows with the best capex efficiency

Our 2011 Credit Suisse Global Energy *Conversion of Resources* theme took the view that future stock market winners will be those that can most efficiently 'Convert' in-hand resources into cash flow. Simple unit volume growth is no longer an acceptable tool, due to the large value gap between natural gas and liquids and major differences in Conversion costs. We measure relative Conversion efficiency by comparing cash flow per debt-adjusted share (*CFDAS*) growth. (See Exhibit 112.) CFDAS growth adjusts for any needed financing or repayments (*shares or debt additions*). For these analyses, we have only included 'larger' players as hidden value (*i.e., acreage*) can cloud this exercise for smaller caps. Companies that are seeing the best CFDAS growth are:

- **US natural gas names such as RRC, EQT:** though clearly US price assumptions will play a key role in this. If gas markets do not tighten in 2013, CFDAS growth will be lower.
- **Liquid Transition E&Ps:** Companies that can replace natural gas production with oil or liquids, e.g., PXP, PXD, NBL lead the CFDAS growth table.
- **Select Majors:** Surprisingly for many in our research last year but a key theme for Credit Suisse was large-cap majors who can grow cashflow and throw off excess cash to theoretically buyback stock, e.g., RDS, MRO, OXY, SU. We note that companies with high upfront shale capex, e.g., HESS and EOG should improve over time as infrastructure and HBP drilling is completed.

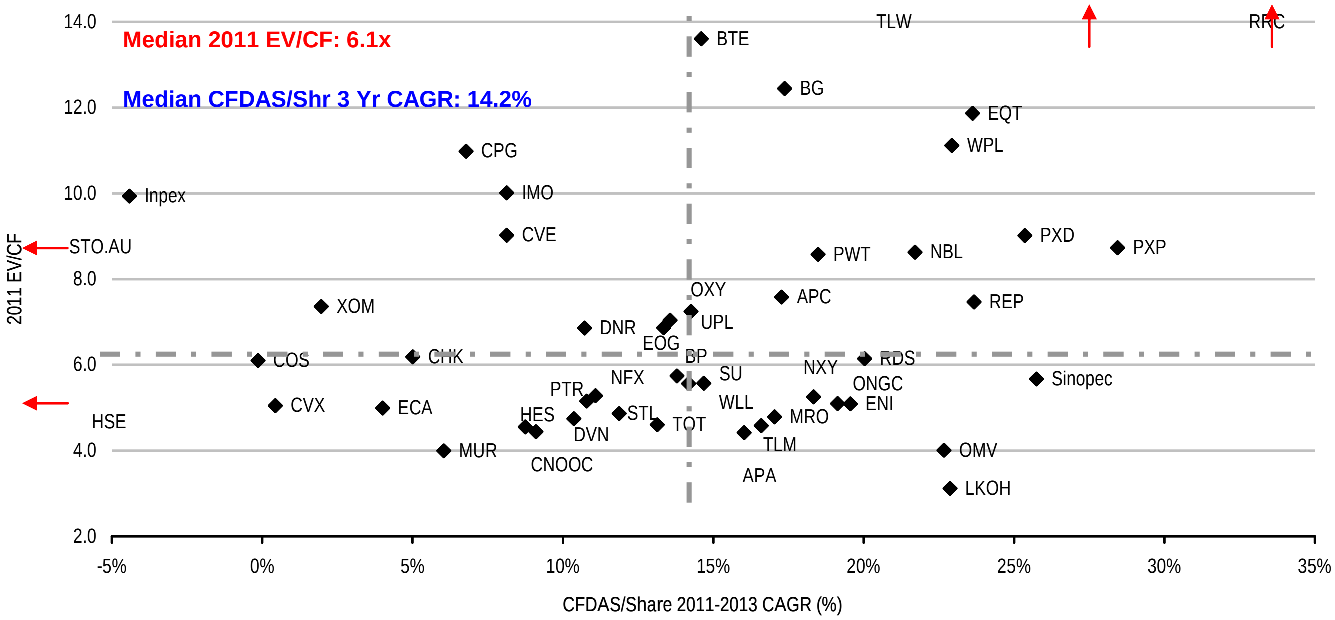
Exhibit 112: Consensus Cash Flow per Debt-Adjusted Share Growth (*CAGR, 2011-2013*)



Source: Bloomberg, Credit Suisse estimates.

For stock selection, we look for companies that are "cheap" to growth. That is companies that trade at low EV/EBIDAX multiples relative to CFDAS CAGRs.

Exhibit 113: 2011 EV/CF vs. Consensus CFDAS Growth (2011-13 *CAGR*) Scatter Plot

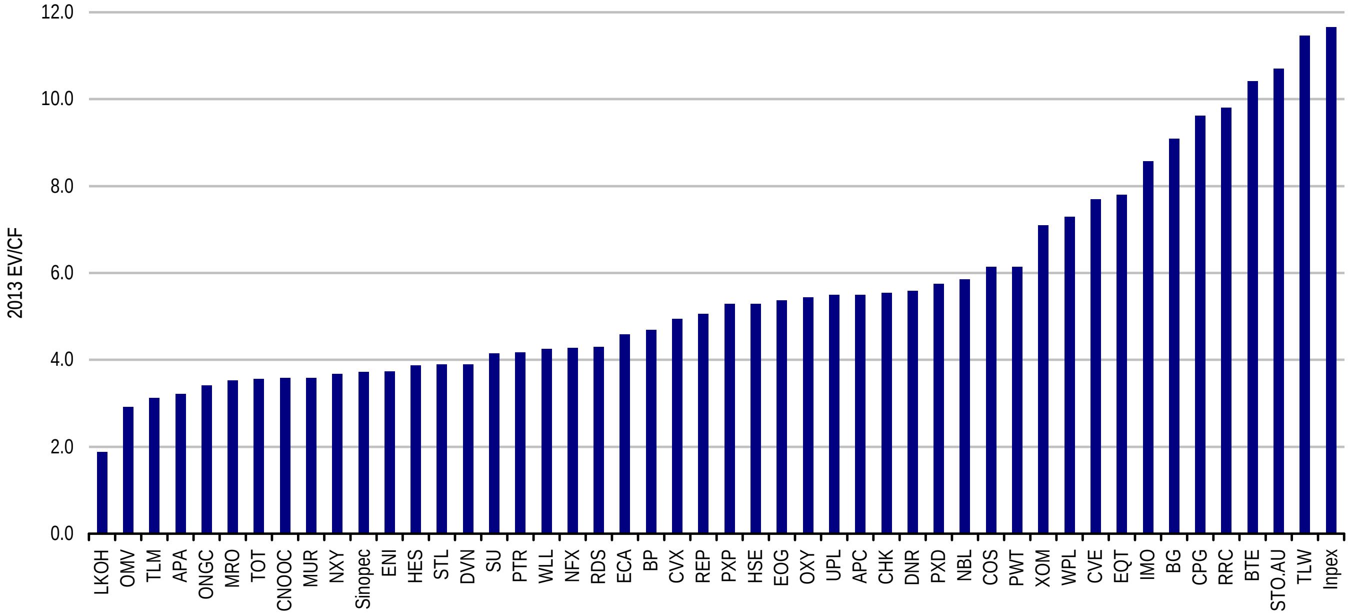


Source: Bloomberg, Credit Suisse estimates.

2013 Multiples Are a Strong Value Gauge

Another important value screen for us is 2013 EV/CF multiples, which incorporate future balance sheets (*forecasted EV*) and expected cashflow, but we also note that low multiples do not tell the whole story because some low multiple stocks lack durable assets. Looking at forward multiples, select large cap E&P producers have fallen into interesting value territory, e.g., HES, MRO, SU, TLM, WLL against the large cap Supermajors.

Exhibit 114: Consensus 2013 Forward EV/CF



Source: Bloomberg, Credit Suisse estimates.

US E&Ps in 2012—Focus on Self-Funded Liquid Transition Stories

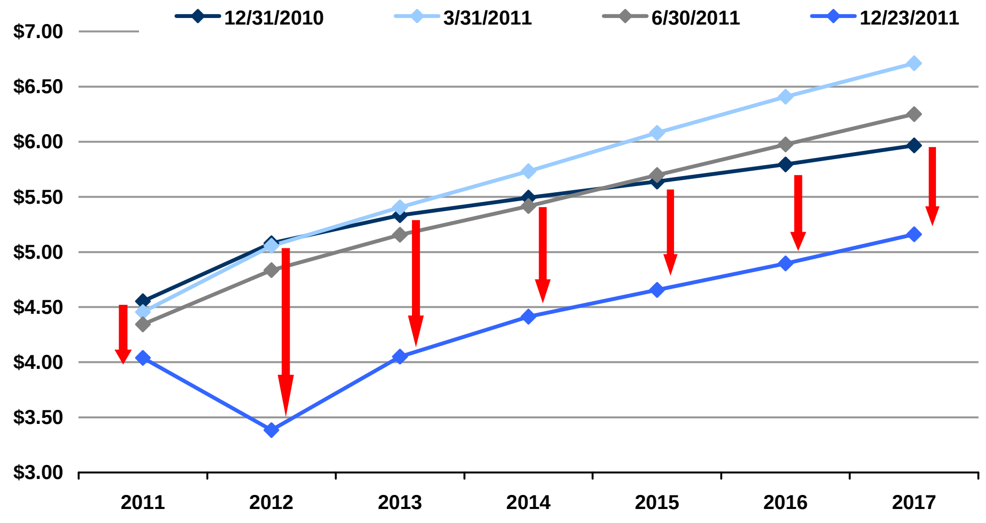
We prefer liquids focused E&Ps with deep, high return project inventories

For US E&P in 2012, we continue to view companies that have transitioned to liquids-focused shale development and are beginning to demonstrate the repeatable growth profile that these assets provide to be most advantaged. In 2011, we saw results improve in leading shale plays, such as the Eagle Ford and Marcellus, and continue to see operators step out to new areas, such as the Utica and new targets in the Permian, in an attempt to replicate shale success. In the SMID-cap group we prefer liquids-focused E&Ps with deep, high-return project inventories that are focused on delivering cash flow (*per share*) growth and are able to fund that growth in an uncertain macroeconomic environment. Our top picks in the SMID-cap E&P group for 2011 are ROSE, EXXI and SFY.

Too Early to Make a Contrarian Bet on Gas

Despite front month gas futures near $3 per MMBtu, the lowest levels we have seen since fall 2009, we expect 2012 to remain a tough year for the gas market. For an industry that is normally very focused on driving absolute production growth, ongoing weak gas prices have producers backing away from continuing to channel capital (*even maintenance capital*) into marginal basins, but the shift to unconventional resources and efficiency gains in that development are offsetting the impact of lower overall activity. Front-month natural gas prices have declined 29% year-to-date and 36% from the recent high *($4.85 per MMBtu on 6/8/11*) to ~$3.10 per MMBtu while the 2012 curve has declined 33% year-to-date to $3.39 per MMBtu from $5.08 per MMBtu. The natural gas futures curve is now trading below $5.00 per MMBtu through 2016.

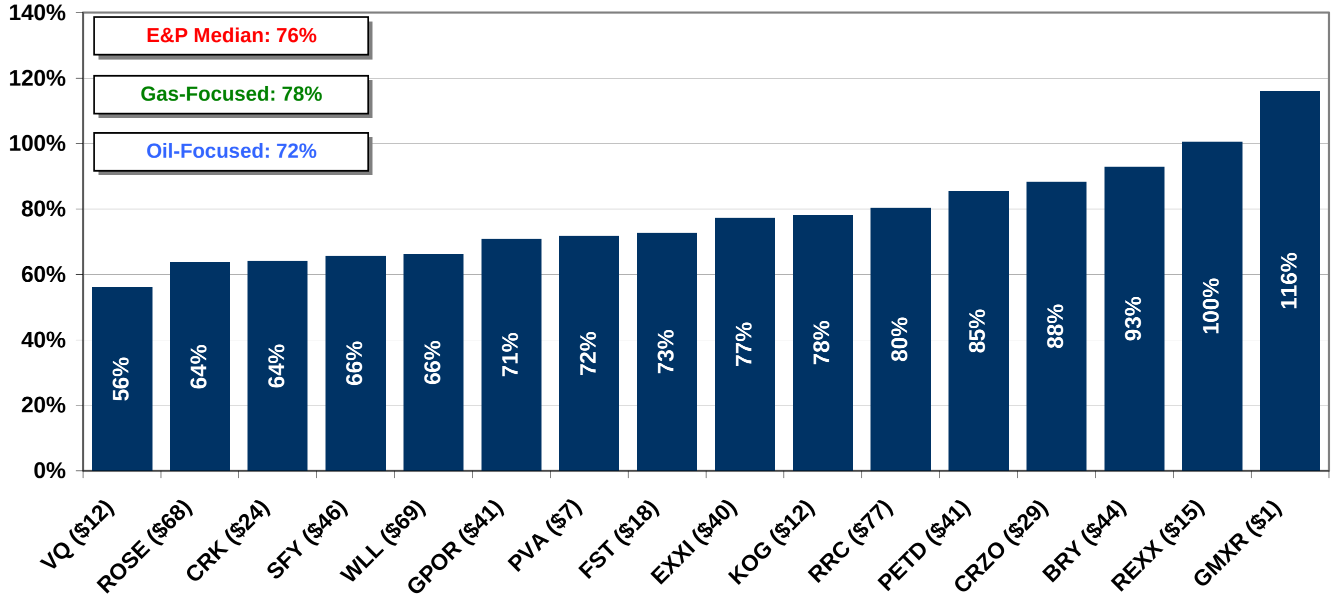
Exhibit 115: Historical Natural Gas Price Futures Curve



Source: Source: Energy Information Administration (Production Survey 914).

While natural gas and gas-leveraged E&Ps continue to come under pressure, we do not think the timing is right to make a contrarian bet on natural gas in equities. The Global Commodities team lowered its 2012 NYMEX gas forecast on December 14, 2011 (*see note titled "Marking-to-Market 4Q2011, Adjusting US Gas and WTI"*) to $3.50 per MMBtu (*from $4.40 per MMBtu*) and continues to see risk to the downside as we remain on track for near-record inventory levels at the end of March 2012. On valuation, gas-focused E&Ps in our coverage universe trade at a 3% discount our 'PD Plus' NAV (*at the futures* *strip*) and 6.7x 2012 and 6.0x 2013 EV/EBITDAX (*unhedged at the futures strip*) compared with the oil-weighted group, which currently trades at a 25% discount to NAV and 5.2x and 4.2x 2012 and 2013, respectively. We estimate the gas-weighted names in under coverage reflect long-term natural gas at $4.75/MMBtu despite natural gas futures trading below $5.00/MMBtu out through 2015. For that reason, we expect gas-focused operators to remain disadvantaged until we see evidence that lower gas prices and levels of gas-focused activity are resulting in lower gas supply.

Exhibit 116: **Price to Risk Weighted (‘*PD-Plus*’) NAV—Credit Suisse Price Forecast**

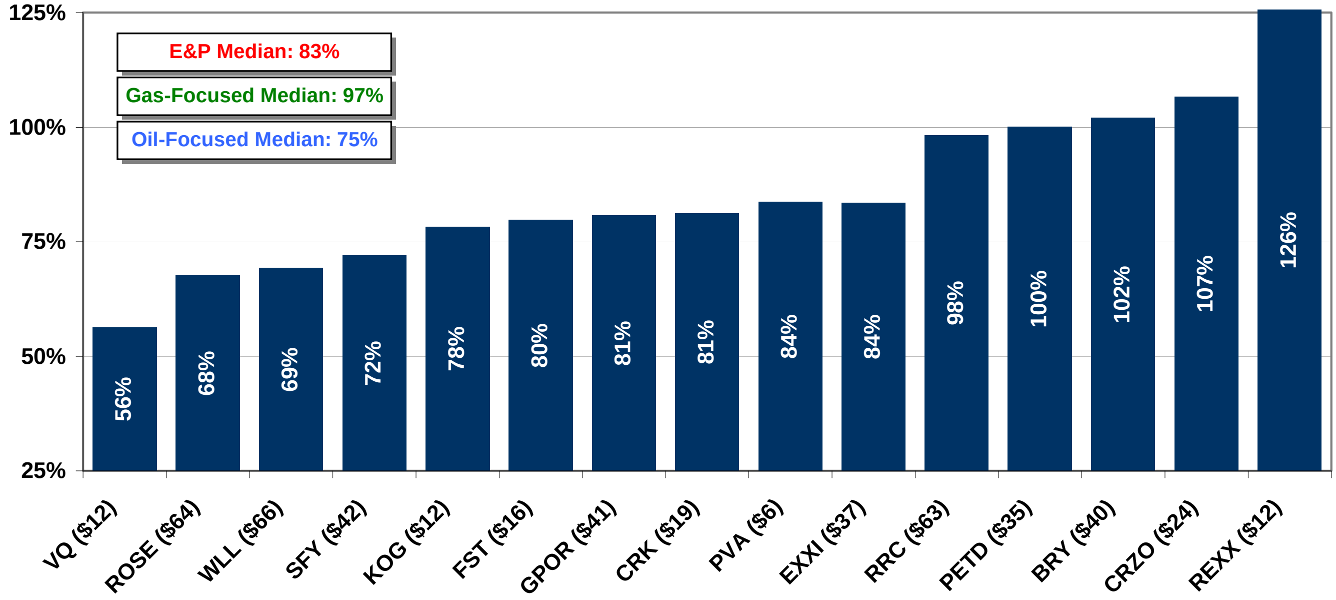


Price Scenario

	2012	2013	2014	2015	2016	2017+	
WTI Oil	$99.00	$113.00	$117.50	$84.00	$84.00	$84.00	*per Bbl*
NYMEX Gas	$3.50	$4.70	$5.10	$5.50	$5.50	$5.50	*per MMBtu*

Source: Company data, Credit Suisse estimates.

Exhibit 117: Price to Risk Weighted ('*PD-Plus*') NAV—at the Futures Strip

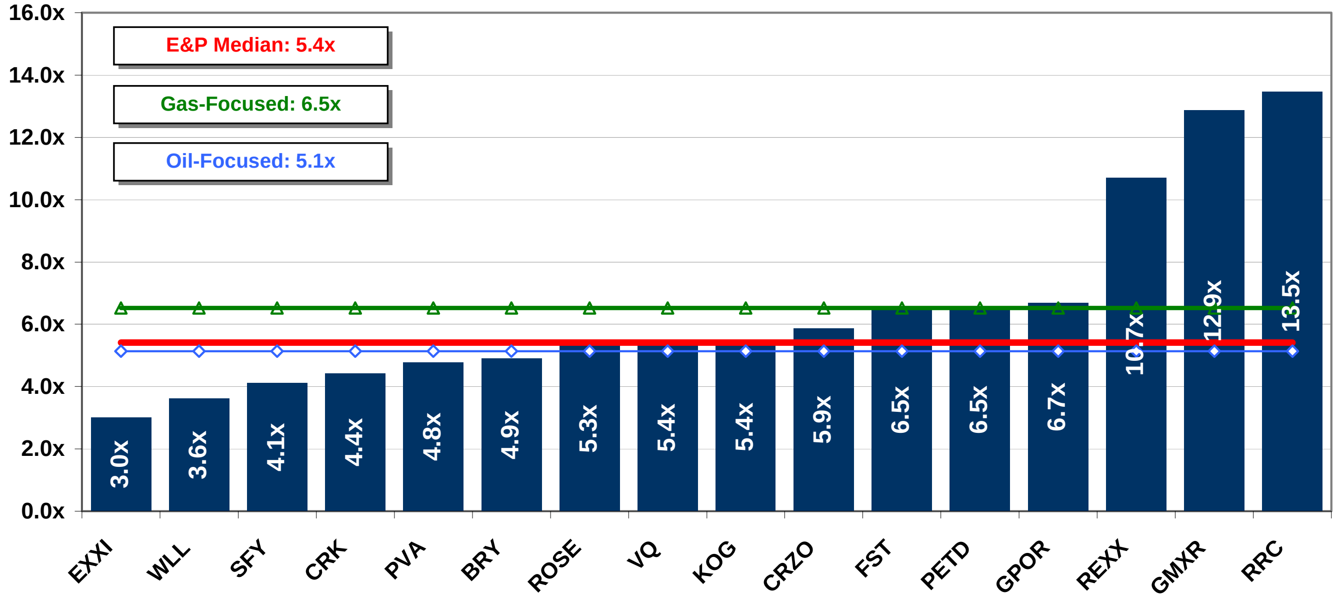


Price Scenario

	2012	2013	2014	2015	2016	2017+	
WTI Oil	$99.16	$96.06	$92.67	$90.93	$90.22	$90.27	*per Bbl*
NYMEX Gas	$3.35	$4.02	$4.38	$4.59	$4.86	$5.13	*per MMBtu*

Source: Company data, Credit Suisse estimates.

Exhibit 118: 2012 Unhedged EV/EBITDAX—Credit Suisse Price Forecast

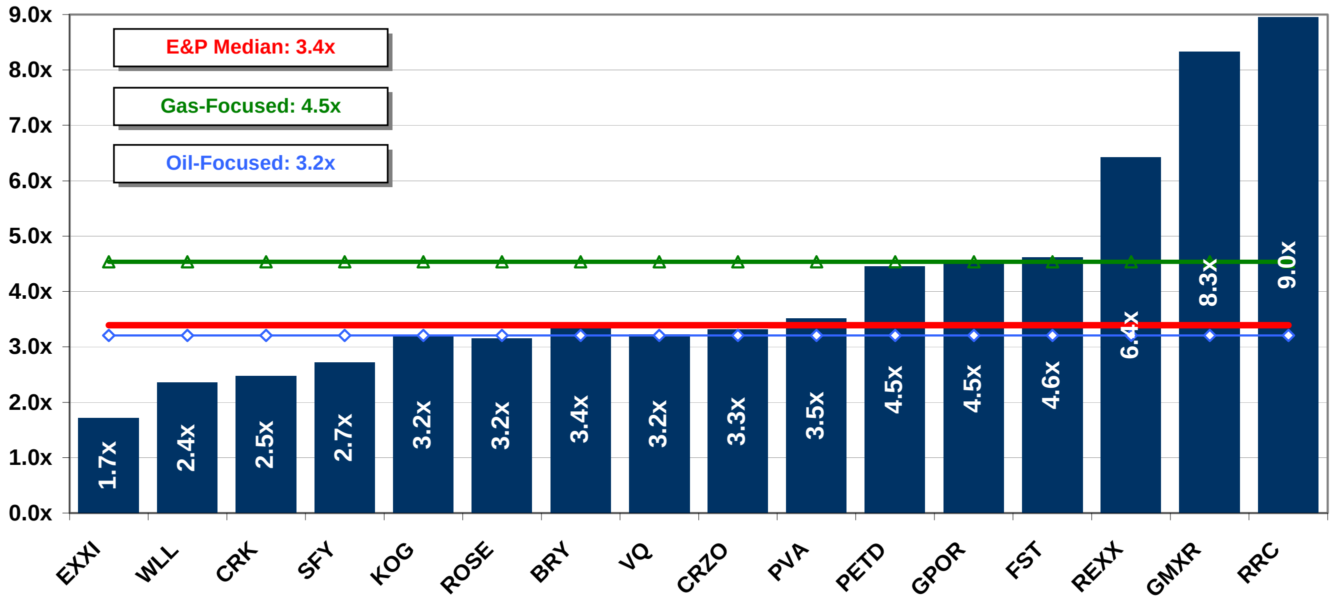


Price Scenario

	2012E	
WTI Oil	$99.00	*per Bbl*
NYMEX Gas	$3.50	*per MMBtu*

Source: Company data, Credit Suisse estimates.

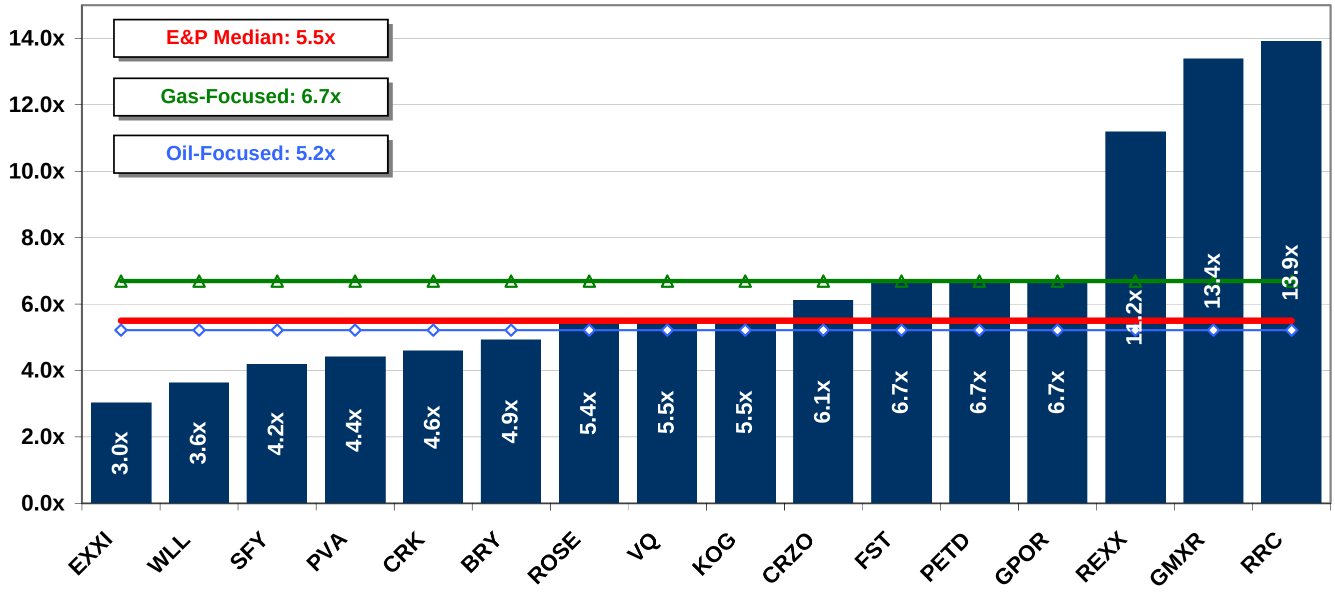
Exhibit 119: **2013 Unhedged EV/EBITDAX—Credit Suisse Price Forecast**



Price Scenario		
	2013E	
WTI Oil	$113.00	*per Bbl*
NYMEX Gas	$4.70	*per MMBtu*

Source: Company data, Credit Suisse estimates.

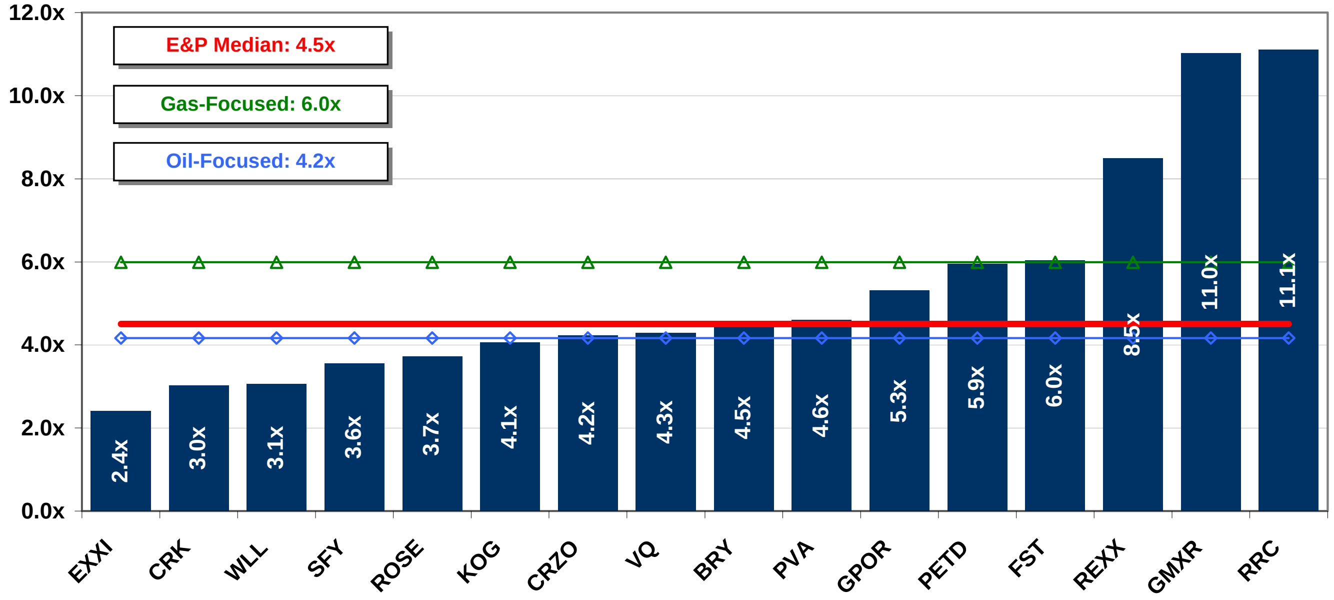
Exhibit 120: **2012 Unhedged EV/EBITDAX—at the Futures Strip**



Price Scenario		
	2012E	
WTI Oil	$99.23	*per Bbl*
NYMEX Gas	$3.35	*per MMBtu*

Source: Company data, Credit Suisse estimates.

Exhibit 121: **2013 Unhedged EV/EBITDAX—at the Futures Strip**



Price Scenario		
	2013E	
WTI Oil	$96.07	*per Bbl*
NYMEX Gas	$4.02	*per MMBtu*

Source: Company data, Credit Suisse estimates.

Plays in Focus and Ways to Play

Attractive Economics in Liquids Basins

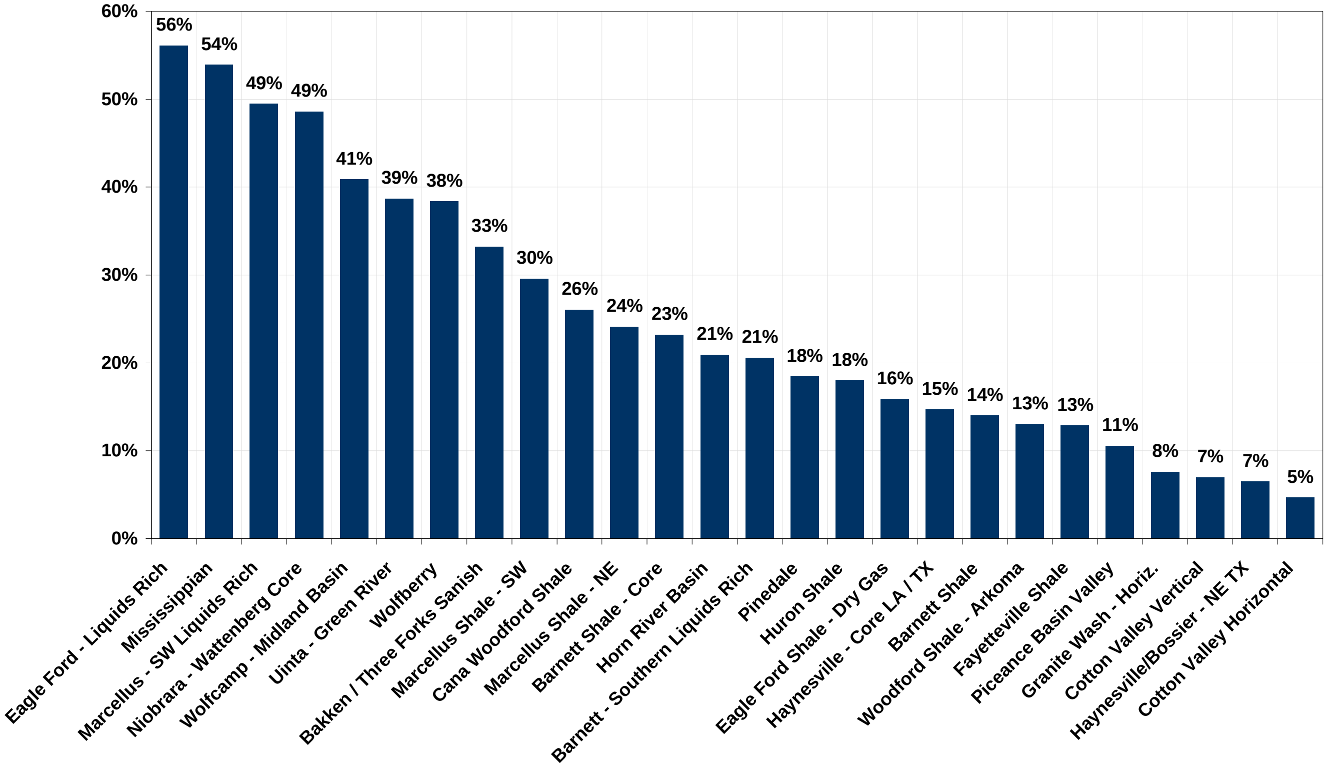
Eagleford, Mississippian, and Core Niobrara lead the pack

Liquids-rich basins continue to provide significantly higher rates of return driven by both higher oil prices and the continued weak natural gas price environment. On average, the liquids-rich plays (*Eagle Ford*, *Marcellus SW Liquids-Rich, Mississippian, Niobrara Core, Bakken*) provide rates of return that are more than 20 percentage points higher than dry gas plays at the current futures strip. Notably, we have added a number of new liquids plays to our basin return analysis (*see Exhibit 122 and Exhibit 123*), which include the horizontal Mississippian, Wolfberry and Wolfcamp plays in the Permian Basin, the Niobrara in the DJ Basin and the vertical Green River play in the Uinta Basin.

Expect Cost Inflation to Moderate

We saw substantial cost inflation in the sector in 2011, primarily driven by the demand for pressure pumping equipment and the consumables required in the well completion process. With expectations for the higher utilization of frac fleets and additional horsepower coming to market, our OFS team believes the pressure pumping market will become more balanced heading into the new year, and therefore we do not expect similar levels of cost inflation in 2012. In 2011, it was evident that the Williston Bakken and Eagle Ford experienced higher cost pressure than other plays and operators are taking steps to increase efficiencies to offset cost increases, including pad drilling and testing new completion technologies.

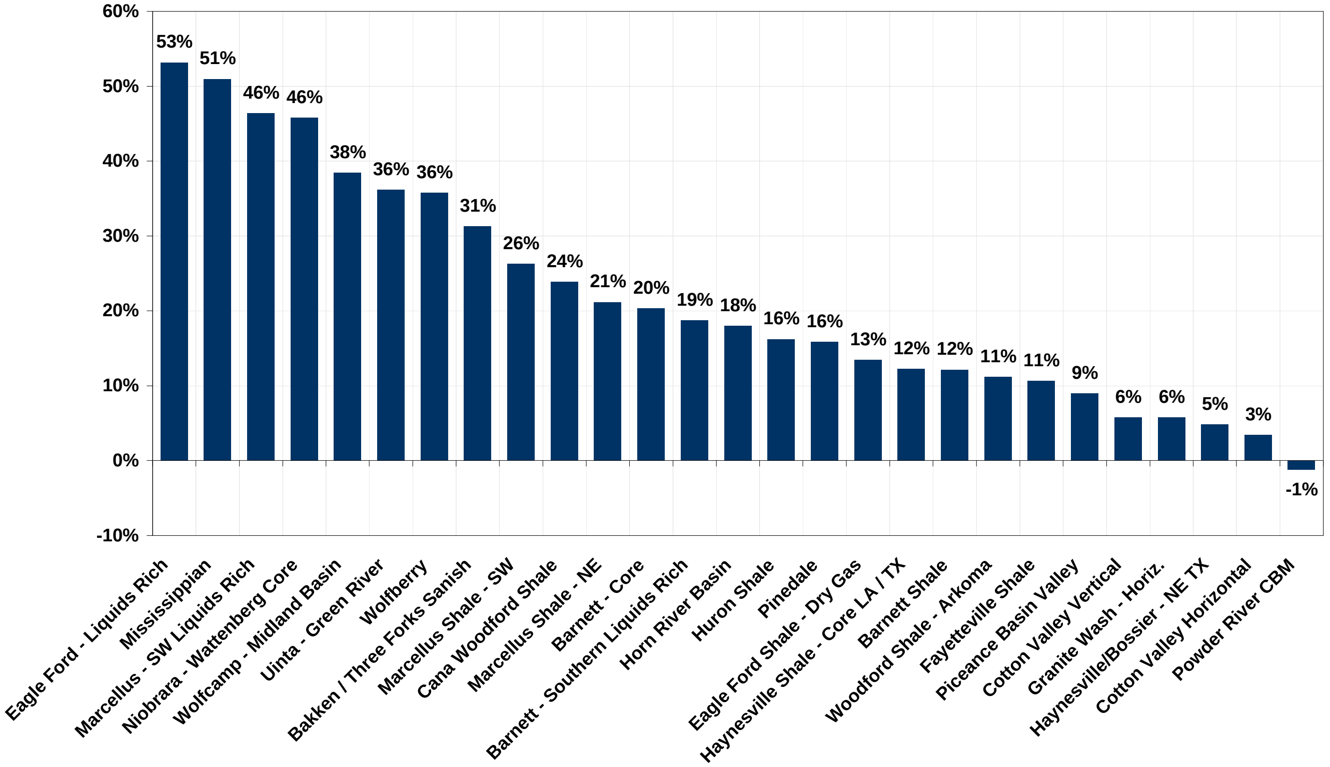
Exhibit 122: US Basin Internal Rates of Return (IRRs)—*Credit Suisse Price Forecast*



Year:	1	2	3	4	5	6	7	8+
WTI Oil:	$99.00	$113.00	$117.50	$84.00	$84.00	$84.00	$84.00	$90.53
NYMEX Gas:	$3.50	$4.70	$5.10	$5.50	$5.50	$5.50	$5.50	$4.90

Source: Company data, Credit Suisse estimates.

Exhibit 123: US Basin Internal Rates of Return (IRRs)—*at the Futures Strip*



Year:	1	2	3	4	5	6	7	8+
WTI Oil:	$99.29	$96.74	$92.98	$91.28	$90.53	$90.53	$90.53	$90.53
NYMEX Gas:	$3.40	$4.06	$4.41	$4.63	$4.90	$4.90	$4.90	$4.90

*Source: Company data, Credit Suisse estimates. * Futures strip as of 12/28/11.*

Eagle Ford Is King

Sweet spots in the Eagle Ford provide some of the best economics in US onshore E&P, whether its BHP's Black Hawk area or ROSE's Gates Ranch prospect. This point is supported by A&D activity, with the Eagle Ford attracting the best $/acre metrics in the US E&P in 2011, from MRO paying $21k per acre for Hilcorp in June 2011 and APC getting roughly $14k per acre for its JV with KNOC in March 2011. This compares to deals in the Marcellus and Bakken that have valued leasehold in a range of $7-8k per acre (*NBL JV with CNX in the Marcellus*). With the build-out of infrastructure in the Eagle Ford, operators are able to get oil and NGLs to Gulf Coast markets where they receive premium pricing relative to WTI and what they have received historically.

Results in the Eagle Ford have continued to improve in 2011. ROSE increased its recovery estimates in Gates Ranch (*Webb County, TX*) to 10 Bcfe (*from 7.4 Bcfe*) in August 2011, and in November determined that tighter well density was required to maximize resource recovery (*ROSE expects to develop Gates Ranch on 60-acre spacing*). In September 2011, SFY also increased its recovery estimates in the Eagle Ford. In McMullen County, TX, the company raised its EUR estimates in the North AWP field (*oil window*) to 395 MBoe (*from 354 MBoe*) and project NPV to $7.3 million (*from $6 million*) assuming $90 oil and $5 gas. In the high-yield condensate part of the play, recovery estimates improved to 615 MBoe (*from 524 MBoe*) and project NPV to $9 million (*from $7.2 million*).

Exhibit 124: **Eagle Ford Operators**

Key Players	Acreage	Shares (MM)	Market Cap ($MM)	Acres per K Basic Shares	Acres per $MM Mkt Cap
PVA	20,000	45.7	$216	0.44	92.70
GDP	40,000	36.1	$461	1.11	86.84
FST	118,000	114.4	$1,500	1.03	78.65
NFX	335,000	134.6	$5,064	2.49	66.15
SFY	78,000	42.5	$1,296	1.84	60.20
CRZO	41,000	39.4	$981	1.04	41.78
MHR	25,074	128.8	$608	0.19	41.27
SM	150,000	64.0	$4,582	2.34	32.74
CRK	24,000	47.6	$743	0.50	32.31
CHK	460,000	659.3	$15,031	0.70	30.60
ROSE	65,000	53.0	$2,373	1.23	27.40
MUR	240,000	193.5	$10,262	1.24	23.39
EOG	561,000	268.9	$26,396	2.09	21.25
GEOI	11,500	25.6	$751	0.45	15.30
MRO	285,000	703.7	$19,359	0.40	14.72
PXP	60,000	141.0	$4,862	0.43	12.34
PXD	116,600	121.9	$10,512	0.96	11.09
EP	170,000	771.2	$19,681	0.22	8.64
APC	300,000	498.0	$37,233	0.60	8.06
COG	53,000	104.5	$8,025	0.51	6.60

Source: Company data, Credit Suisse estimates.

Bakken—Economics Still Stack Up

Sentiment in the Bakken weakened more significantly relative to other oil basins owing to cost inflation and well results that have failed to stack up to Sanish/Parshall as operators have expanded exploration of the Williston. While operators such as NFX, DNR and QEP have slowed operations in the Bakken, others such as CLR, WLL, KOG and OAS are planning to increase activity in the basin in 2012 demonstrating that certain operators still see strong rates of return within the play.

Despite concerns that service cost inflation is eroding margins in the Bakken, we argue operators such as KOG are still is capable of delivering strong project returns from its core asset base where the company estimates EURs of 750-900 MBoe. Assuming $10MM drill and complete costs and 800 MBoe well recoveries, we estimate the project delivers a $13MM NPV and 49% IRR at the futures strip. WLL continues to delineate and add to its inventory in the Williston. Currently, WLL believes that it has completely derisked its Cassandra, Tarpon, and Hidden Bench prospects and has derisked approximately 52% of its Lewis & Clark/Pronghorn prospects (*389 out of 733 potential locations*). In addition, successful exploration in WLL's Starbuck (*near the Gobbs 17-8 #1H well that posted a 24-hr peak IP rate of 1,818 Boe/d in Roosevelt County, MT*) and Missouri Breaks (*near the Storvik 7-6 #1H well that posted a 24-hr peak IP rate of 2,066 Boe/d in Richland County, MT*) prospects in Montana would provide additional inventory upside. Notably, WLL's 33 wells to date in the Lewis & Clark/Pronghorn have exhibited shallower declines indicating that the wells are potentially more economic. To date, 21 wells have exhibited 90-day IP rates of 387 Boe/d. Assuming a $7MM completed well cost and $80 per Bbl realized, 33% of the well cost (*net of royalty*) would be recouped in that timeframe.

Exhibit 125: **Key Bakken Operators**

Key Players	Acreage	Shares (MM)	Market Cap ($MM)	Acres per K Basic Shares	Acres per $MM Mkt Cap
WLL	680,137	117.4	$5,423	5.79	125.42
OAS	303,231	92.5	$2,674	3.28	113.41
BEXP	375,800	117.3	$4,280	3.20	87.81
NOG	115,700	63.2	$1,498	1.83	77.25
CLR	901,370	180.5	$11,975	4.99	75.27
USEG	5,500	27.3	$78	0.20	70.26
AXAS	20,000	92.2	$299	0.22	66.94
KOG	155,000	257.6	$2,329	0.60	66.55
GEOI	37,000	25.6	$751	1.45	49.24
REN	33,400	61.1	$686	0.55	48.70
DNR	266,000	391.6	$5,937	0.68	44.80
SM	205,500	64.0	$4,582	3.21	44.85
HES	600,000	339.9	$18,913	1.77	31.72
NFX	140,000	134.6	$5,064	1.04	27.64

Source: Company data, Credit Suisse estimates.

Early Days in the Utica

While data have been limited to date, early results suggest that, not only are Utica economics good, but they could be some of the best in U.S onshore E&P. Early results that piqued interest in the Utica came from CNX, which reported a 1.5 MMcfe/d flow rate from an unstimulated vertical test (*Barnesville #1*) in Belmont County, OH, in October 2010 and RRC, which delivered a seven-day average production rate of 4.4 MMcfe/d from its Zahn #1H well in Beaver County, PA, in the dry gas window of the play.

In late September 2011, CHK delivered initial results on four wells that appear to justify the land grab that has driven operators such as HES to pay up to $9k/acre to enter the play. CHK reported two wells in Carroll County, OH, the Mangun 22-15-5 8H well that initially produced 1.5 MBoe/d (*66% liquids*) from a 6,200 foot lateral and the Neider 10-14-5 3H well that produced 1.6 MBoe/d (*61% liquids*) from a 4,200 foot lateral. In Harrison County, OH, the Buell 10-11-5 8H well produced 3 MBoe/d (*47% liquids*) from a 6,400 foot lateral. In Beaver County, PA, CHK reported that the Thompson 3H well produced 6.4 MMcf/d of dry gas from a 4,300 foot lateral.

CHK is the clear front runner in the Utica with plans to run 10 rigs in the play by year-end 2011, ramping up to 20 in 2012 and 40 by 2014. According to the Ohio Department of Natural Resources (*ODNR*), there are currently 76 horizontal wells permitted in the Utica and only 14 wells drilled. There have also been 58 vertical stratigraphic test wells permitted, with 11 drilled.

Exhibit 126: **Utica Operators**

Key Players	Acreage	Shares (MM)	Market Cap ($MM)	Acres per K Basic Shares	Acres per $MM Mkt Cap
CHK	1,357,500	659.3	$15,031	2.06	90.31
GPOR	62,500	55.0	$1,634	1.14	38.24
PETD	30,000	23.6	$828	1.27	36.21
REXX	11,000	44.4	$645	0.25	17.05
CNX	100,000	226.8	$8,259	0.44	12.11
HES	185,000	339.9	$18,913	0.54	9.78
APC	200,000	498.0	$37,233	0.40	5.37
DVN	110,000	403.9	$24,755	0.27	4.44
CRZO	1,500	39.4	$981	0.04	1.53
XOM-XTO	50,000	4,793.2	$392,612	0.01	0.13

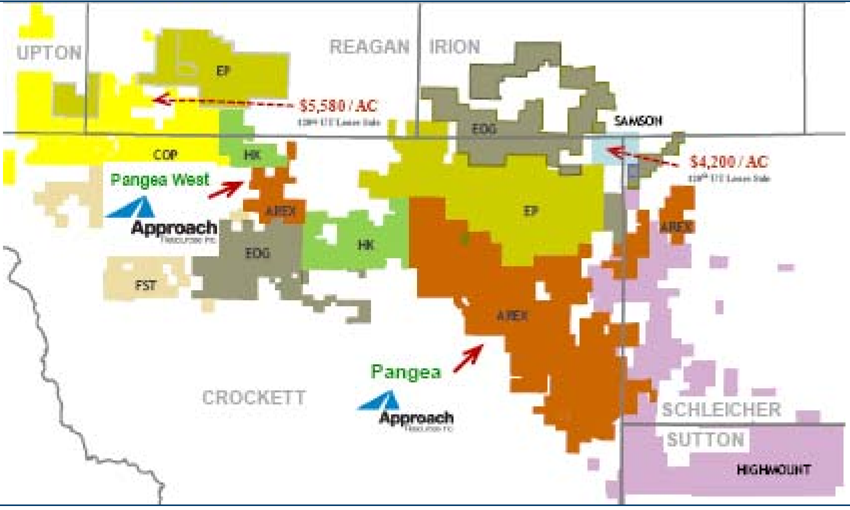
Source: Company data, Credit Suisse estimates.

Permian—Stacked Oil Pay

The Permian is poised to remain an area of focus in 2012 with a number of new horizontal oil and vertical combination projects being tested. The recent focus in the Permian has been on a number of stacked horizons in the Delaware Basin in southeastern New Mexico and West Texas, as well as in the Midland Basin where operators are targeting the horizontal Wolfcamp.

In the Midland Basin, the Wolfcamp shale has been receiving increased attention on the back of improving well results out of EOG and AREX. EOG reported peak initial production of 1,141 Boe/d from five recent Wolfcamp horizontal wells and bumped EUR expectations to 320 MBoe from 270 MBoe in 4Q11. Given strong results in the play EOG is increasing activity from a two operated rig program in 2011 to four rigs in 2012. AREX, also in the southern Midland Basin, is targeting the vertical Wolffork play as well as the horizontal Wolfcamp. AREX recently delivered its strongest three Wolfcamp horizontal wells to date with average initial production rates of 884 Boe/d and is currently estimating EURs of 450 MBoe.

Exhibit 127: **West Texas Southern Midland Basin Operators**



Source: Approach Resources.

With two recent deals in the Delaware Basin, activity could be on the upswing in the Bone Spring and Wolfcamp there as well. In November 2011 CXO paid $330 million for 114k net acres (*primarily in Pecos County, TX*), and in December 2011 CRK bought 44k net acres in Reeves County, TX for $333 million. CXO expects vertical Wolfbone wells costing $4-6 million to recover 200-400 MBoe.

Uinta—Strong Returns Could Drive Oil Growth

NFX offered a comprehensive update on the Uinta in July 2011 after completing the acquisition of HNR that brought the company's position in the basin to 250k net acres. NFX estimates it has 700 MMBoe of resource potential in the Uinta coming from shallow vertical development in the Green River, deep vertical development in the Wasatch and horizontal development in the Uteland Butte formation. Operators have also discussed the potential for additional horizontal oil shale targets in the Mahogany and Black Shale, which both lie at shallower depths than the Uteland Butte.

In Monument Butte, NFX plans to drill 10 wells in the Uteland Butte in 2011 with wells drilled to date having initial production rates of ~500 Boe/d and 30-day average rates of 370 Boe/d. West of Monument Butte in Lake Canyon, BBG and BRY are also testing the Uteland Butte horizontally. While costs are higher in Lake Canyon (*$4.5 million drill and complete vs. $2.8 million for NFX*) initial production and 30-day rates have been more robust at 1,058 Boe/d and 574 Boe/d, respectively from four producers.

While the economics appear to stack up well in the Uinta, there are concerns about the capacity of refiners to take additional black and yellow wax crude. Wax refining capacity is estimated at 60 MBbls/d with current production out of the basin estimated at 43 MBbls/d. Notably, wax crude has historically traded at a 10-15% discount to WTI, but recent work by our refining team suggests that the recently announced supply agreement for wax crude between TSO and NFX would lock in a differential closer to a ~25% discount and any further greenfield refining expansions would require differentials in the range of 25-30%. While project economics would likely withstand the wider differentials, the timing of any further capacity additions could potentially put a lid on growth near/intermediate-term.

Exhibit 128: **Uinta Basin Operators**

Key Players	Acreage	Shares (MM)	Market Cap ($MM)	Acres per K Basic Shares	Acres per $MM Mkt Cap
BBG	124,000	47.7	$1,604	2.60	77.29
BRY	129,000	51.9	$2,057	2.49	62.72
NFX	250,000	134.6	$5,064	1.86	49.37
EP	190,000	771.2	$19,681	0.25	9.65
DVN	47,774	403.9	$24,755	0.12	1.93

Source: Company data, Credit Suisse estimates.

Niobrara—Strong Results in Wattenberg

Momentum in the Niobrara has taken a gradual turn for the better in 2H11, with APC, NBL, and PETD all increasing recovery estimates in the core Wattenberg field. While results outside of Wattenberg in the DJ have been spotty, operators such as WLL, DVN and APC remain optimistic about the oil opportunity in the Niobrara outside of Wattenberg. At its October analyst day PETD suggested EUR estimates in Wattenberg were outperforming its 290 MBoe type curve where it now estimates recoveries of 310 MBoe. PETD reported initial average initial production and 30-day average rates of 629 Boe/d and 476 Boe/d, respectively in Wattenberg. Three wells drilled in PETD's Krieger prospect, which is northeast of Wattenberg, have underperformed the 290 MBoe type curve.

In November, APC unveiled its expectations in the Niobrara, where it holds 350k net acres in the Wattenberg field holding an estimated 0.5-1.5 BBoe of net resources. APC estimates it has 1,200-2,700 locations and expects well recoveries in a range of 300-600 MBoe. The company's first 11 Niobrara and Codell horizontals had average initial production rates of 600 Bbl/d and 1.5 MMcf/d. APC is optimistic about the opportunity in the Niobrara outside of Wattenberg where the company holds another 910k net acres in the DJ and Powder River Basins. Results have not been as robust as they have been in the Wattenberg with disparities in reservoir energy being the important differentiating variable.

At its November analyst day, NBL demonstrated improving results in the Niobrara, where the latest 18 horizontal wells are, have expected recoveries of 355 MBoe, or 22% above the initial 23 wells drilled. NBL estimates 1.3 BBoe of net risked resource on 840k net acres, and expects EURs of over 310 MBoe on ~400k net acres in the Wattenberg field.

Exhibit 129: **DJ Basin Operators**

Key Players	Acreage	Shares (MM)	Market Cap ($MM)	Acres per K Basic Shares	Acres per $MM Mkt Cap
PETD	70,500	23.6	$828	2.99	85.10
CRZO	59,000	39.4	$981	1.50	60.12
AXAS	15,700	92.2	$299	0.17	52.55
NBL	840,000	176.6	$16,386	4.76	51.26
CHK	640,000	659.3	$15,031	0.97	42.58
EOG	400,000	268.9	$26,396	1.49	15.15
APC	550,000	498.0	$37,233	1.10	14.77
CLR	73,009	180.5	$11,975	0.40	6.10
SM	25,000	64.0	$4,582	0.39	5.46

Source: Company data, Credit Suisse estimates.

Mississippian—Recent JV Helps to Affirm Resource Potential

Activity in the Mississippian located on the northern Oklahoma/southern Kansas border is basically limited to a few operators including SD, RRC, DVN, UNT and CHK. SD is the primary operator having drilled 195 horizontal wells to date (*approximately half of the 400 horizontal wells drilled overall*). Development of the play should ramp in 2012 as more capital is diverted to the play in light of recent updates. SD currently estimates 350-500 MBoe EURs with a ~60% oil cut and noted that it plans to ramp to 45 rigs in the play by the end of 2013 (*plans to add a rig a month*) from 20 rigs currently. RRC recently provided a 485 MBoe EUR estimate with a ~70% liquids cut and noted that it plans to initiate development of the play with a ‘couple of rigs’ in 2012.

Recent JV deals have helped to affirm the resource potential of the play. On December 23, 2011, SD announced that it entered into a JV with Repsol for a nonoperated interest in 363,636 net acres in the Mississippian and Extension Mississippian for $1 billion (*$250MM up front and $750MM in drilling carry over 3 years*), which, when discounted back, equates to ~$2,400/acre. Assuming that the core acreage (*113,636 net acres*) is worth ~$5,500/acre, the Extension Mississippian acres are then worth approximately $1,000/acre. SD also recently completed a $500MM *($250MM up front and $250MM in drilling carry over three years*) JV in August 2011 with Atinum partners for 113,000 net acres in the core Mississippian, which equates to ~$4,000/acre discounted back. We note that although the economics of the play appear to be displaying one of the best returns in onshore E&P, acreage values are still lower than those being recorded in the Eagle Ford and the Utica (*still early in the exploration phase*), where recent deals have valued acreage at +$10,000/acre. We would expect further evidence of repeatability of well results will drive other operators into the basin and give current acreage holders leverage moving forward.

Exhibit 130: **Mississippian (*Kansas and Oklahoma*) Operators**

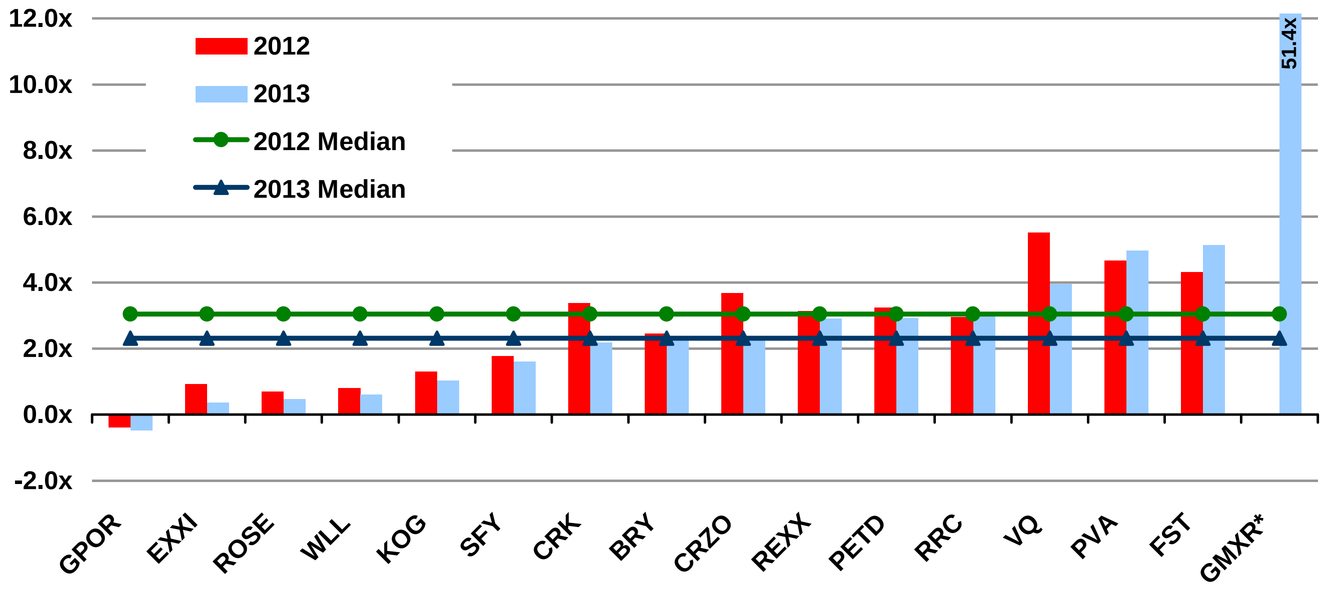
Key Players	Acreage	Gross/Net?	Shares (MM)	Market Cap ($MM)	Acres per K Basic Shares	Acres per $MM Mkt Cap
SD	1,500,000	Net	412.1	$3,472	3.64	432.04
CHK	1,400,000	Net	659.3	$15,540	2.12	90.09
UNT	45,000	Net	48.2	$2,266	0.93	19.85
RRC	105,000	Net	161.3	$10,214	0.65	10.28
DVN	210,000	Net	403.9	$25,324	0.52	8.29

Source: Company data, Credit Suisse estimates.

Funding Risk amid an Uncertain Macro Environment

With an uncertain outlook for the global economy, we believe Net Asset Value (*NAV*) becomes a relatively less relevant driver of valuation as capital funding concerns grow due to the potential for falling cash flows. NAV’s for E&Ps are realized when a capital plan is accordingly executed, but we think that that in a potentially lower oil price environment the resulting cash flows will drive either additional financing needs to fund development or will require a reduction in capital spending plans.

Exhibit 131: **Net Debt-to-Cash Flow, Hedged at Futures Strip (*$94.16/$3.36 in 2012 and $91.79/$3.99 in 2013*)**



Source: Company data, Credit Suisse estimates. **GMXR generates negative cash flow at the strip for 2011.*

Preference for Underleveraged Balance Sheets

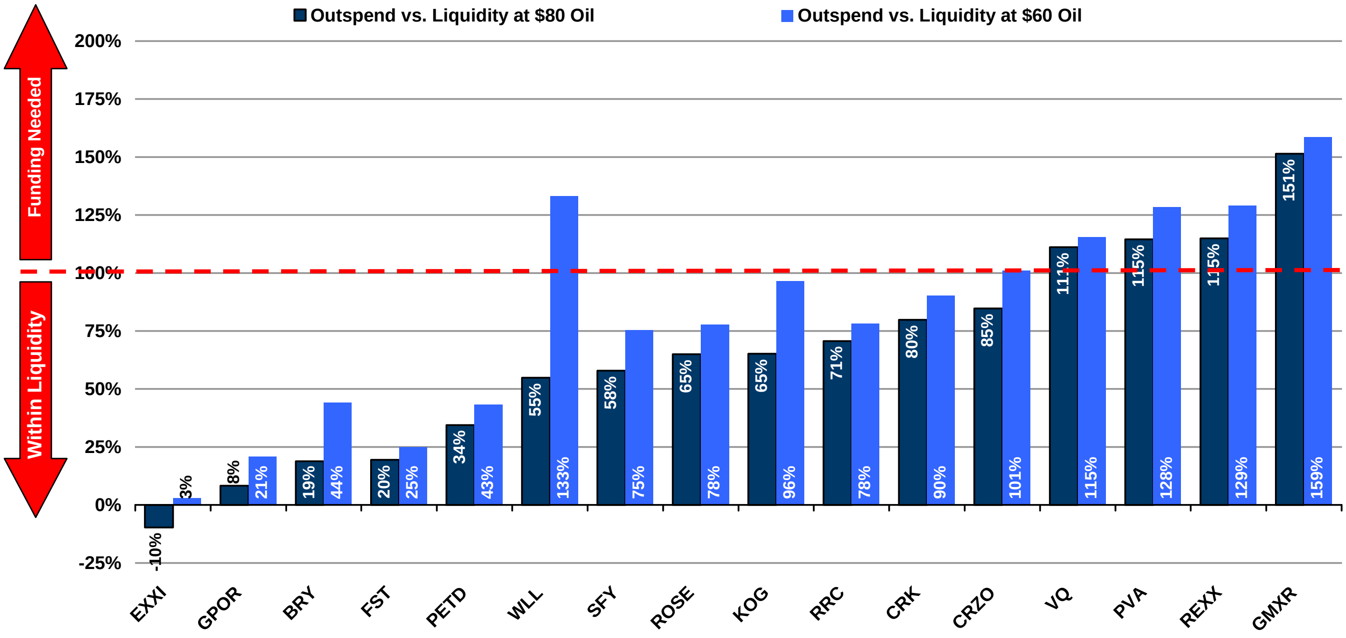
With a focus also on balance sheet strength, we look at net debt-to-cash flow multiples for the group in 2012 and 2013 with commodity prices at the futures strip (*$94.09/Bbl WTI and $3.37/MMBtu gas in 2012 and $91.81/Bbl WTI and $3.99/MMBtu in 2013*). At the strip in 2013, 76% of the companies in this analysis maintain ratios below 4.0x, which is significant in that typical bank credit facility covenants typically require total leverage (*net debt-to-EBITDA*) to remain below 4.0x. GPOR and EXXI screen the best at -0.5x and 0.5x, respectively, while GMXR at 51.4x, FST at 5.1x and PVA at 5.0x are the most stretched in 2013.

Outspending Cash Flow

Projected outspend (*capital expenditures minus projected cash flows*) versus current liquidity (*cash plus undrawn portion of the credit facility*) is an important measure to assess which operators are most susceptible to funding risk. A low level of outspend in comparison to current liquidity (*in our analysis <100%*) would provide a cushion to a continued weak oil price environment over the near-to-medium term.

At $80 per Bbl WTI 76% of our the E&P companies in this analysis have the liquidity in place to fund projected capital spending through 2012. GMXR, REXX, PVA and VQ by our models do not have liquidity currently in place to fund expected spending through 2012. Assuming $60 per Bbl WTI, 65% of the group is funded, though we expect that E&Ps would pare back capital spending plans materially to conserve revolver availability (*see Exhibit 132*).

Exhibit 132: Outspend vs. Liquidity Position at $80 per Bbl and $60 per Bbl Oil



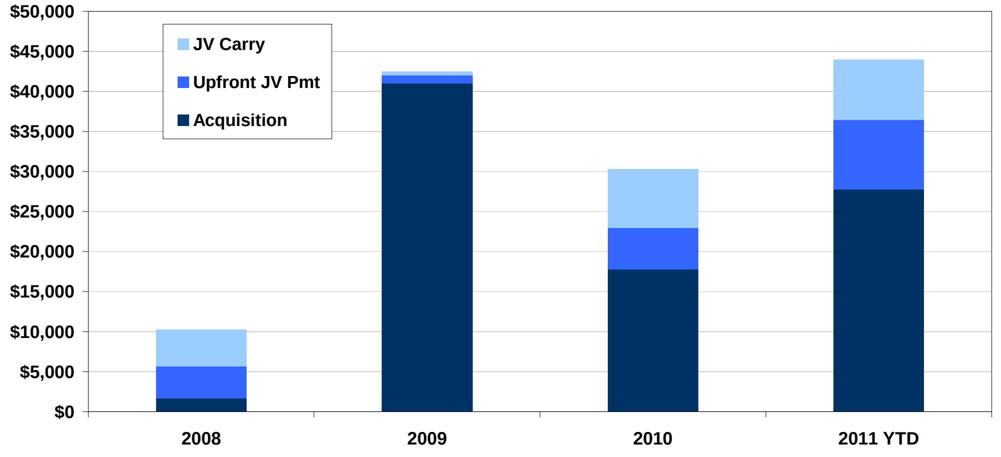
Source: Company data, Credit Suisse estimates.

M&A Activity to Remain Elevated into 2012

We expect M&A and JV activity to remain high in 2012. In 2011, $44 billion of M&A and JV activity has outpaced the $30.3 billion of activity in 2010. Even including XOM's acquisition of XTO (*$41 billion*), 2011 is also exceeding the level of M&A and JV activity in 2008 and 2009. More broadly, we think the recent deals support premium valuations for small and mid-cap E&Ps that have barely scratched the surface of their large resource potential.

Besides the clear cost of capital advantage that the integrateds have over independents, as well as longer investment horizons, we see the potential for upside to our NAVs from the following areas, 1) inventory to be drilled out beyond the typical five years included in our NAVs, 2) technological innovation that could improve recoveries or drive down costs over time, 3) increasing the pace of development that would increase the present value of the project inventory, 4) linkage between natural gas liquids and oil related markets (*e.g., chemical crackers*) for pricing assumptions, 5) a longer term bet that infrastructure will be in place that will allow operators to take advantage of the arbitrage opportunity between US and global gas markets. We expect interest in companies with large footholds in the best return plays will remain strong, which include Eagle Ford, Marcellus and Bakken exposed E&Ps. In our coverage universe, we continue to view RRC, KOG, WLL, ROSE, SFY, and EXXI as potential acquisition targets.

Exhibit 133: Acquisition and JV's in 2011 Exceeded 2009 Levels



Acquisition	$1,700	$41,000	$17,767	$27,741
Upfront JV Pmt	$4,000	$1,033	$5,180	$8,673
JV Carry	$4,575	$413	$7,344	$7,542
TOTAL	**$10,275**	**$42,446**	**$30,291**	**$43,956**

Source: Company data, Credit Suisse estimates.

Exhibit 134: Recent US Upstream M&A Activity

				Notable Gas Shale Joint Venture Agreements / Acquisitions				
				Transaction Value ($MM)				
Type	**Date**	**Seller**	**Buyer**	**Total**	**Upfront**	**Drilling Carry**	**Joint Venture / Acquisition Package**	**$ per Acre**
JV	**9/7/2011**	**CNX**	**Hess (HES)**	$593MM	$59	$534	***Utica -*** *CNX sells a 50% working interest to Hess (HES) in CNX's 200k net acres in the Eastern Ohio Utica Shale. HES will pay $59MM up front at the close and $534MM of drilling carry over 5 years. The JV development plan calls for HES to operate 80k net acres in Jefferson, Harrison, Guernsey and Belmont Counties. Discounting total value by acreage comes to $4,480/acre. We are assuming approximately $2000/acre for 120k net acres of dry gas/oil resulting in ~$8,200/acre for the 80k net acres of wet gas (core).*	$5,930
Acquisition	**9/8/2011**	**Marquette**	**Hess (HES)**	$750MM	$750	$0	***Utica -*** *Hess (HES) announced that it has added on an additional 85k net acres through the acquisition of Marquette Exploration and other leases in the Ohio Utica shale. The leases are in Jefferson, Harrison and Belmont counties.*	$8,824
JV	**9/28/2011**	**CRZO**	**Gail (India)**	$95MM	$64	$31	***Eagle Ford*** *- Carrizo (CRZO) announced that it has entered a JV with GAIL (India Integrated gas company) for a 20% interest in CRZO's 20,200 net (4,040) acres in La Salle County, TX and associated production of 340 Bbl/d oil and 760 Mcfpd. Valuing production at about $75k per flowing Bbl and $7.5k per flowing Mcf results in about $15k/acre, but given that production sold was in early development stages better to apply $40k per flowing which would result in about $19k/acre.*	$16,213
Acquisition	**9/28/2011**	**Private Company**	**KOG**	$235MM	$235	$0	***Bakken*** *- Kodiak Oil & Gas (KOG) announced that it will acquire 13.5k net acres in Williams County, ND with associated production of 3 Mboed. The deal is expected to close at the end of October 2011. Assuming $45k per flowing Boe given high decline rate for 3 MBoed of production or ($135MM). You would get approximately $7,400/acre.*	$7,407
Acquisition	**10/17/2011**	**BEXP**	**Statoil (STO)**	$4,400MM	$4,400	$0	***Bakken*** *- Brigham Exploration (BEXP) announced that it has entered an agreemen to be acquired by Statoil for $4.4B. BEXP had 235.2k net acres in the core and 375.8k net Williston Basin acres. At the time of the acquisition BEXP had 21 MBoe/d flowing. Assuming $75k per flowing Boe, or $1.58B, the acreage value is $7,500/acre.*	$7,517
Acquisition	**11/2/2011**	**Private Sellers**	**CXO**	$330MM	$330	$0	***W. Tx Permian -*** *CXO entered into a purchase agreement with multiple parties for aggregate consideration of $330MM for 114k net acres in the northern and southern portions of CXO's Delaware Basin Bone Spring play (primarily in Pecos County, TX). Acreage acquisition includes 1,500 Boe/d of flowing production.Backing out production at $80k per flowing acreage value comes out to $1,840 per acre The deal is expected to close December 2011.*	$1,842
JV	**11/3/2011**	**CHK**	**Undisclosed**	$2,140MM	$640	$1,500	***Utica*** *- Chesapeake (CHK) announced it has entered into a JV with an undisclosed international partner for a 25% interest in 570K net acres in the Utica for $2.14B. The JV covers acreage in all or a portion of 10 counties in eastern Ohio. The JV will be in the form of an upfront payment of $640MM and $1.5B in carry through the end of 2014. The headline acreage value works out to $15k/acre, but discounting back the carry results in $13k/acre.*	$15,018
Acquisition	**11/14/2011**	**Private Company**	**KOG**	$590MM	$590	$0	***Bakken*** *- Kodiak Oil & Gas (KOG) announced that it will acquire 50k net acres in Williams and McKenzie Counties, ND for $540MM in cash and $50MM in shares. 30k net acres are contiguous to lands acquired and closed in October 2011 and the remainder in northern Williams County. Associated production is approximately 3,500 Boe/d with 3.1 net wells awaiting completion. Assuming $75k per flowing BOE or $262.5MM, you would get $6,550/acre. Expected to close early 2012.*	$6,550
JV	**11/29/2011**	**NXY**	**INPEX**	$700MM	$350	$350	***Horn River Basin*** *- Nexen announced that it will sell a 40% working interest in its Horn River Basin assets to a consortium led by INPEX and will remain the operator The total working interest will be $700MM with 50% upfront and 50% capital carry. The deal is expected to close in 1Q12 at which time $600MM will be due to NXY. NXY has 300k acres in the HRB and assuming minimal production and carry over 3 years would value the acreage at $5,7040acre.*	$5,708
Acquisition	**12/5/2011**	**Eagle Oil & Gas**	**CRK**	$332.7MM	$333	$0	***W. Tx Permian -*** *CRK entered into a purchase agreement with Eagle Oil & Gas and certain other parties to acquire acreage in the Delaware Basin in West Texas in Reeves County, TX, which are prospective for the development in the Bone Spring and Wolfcamp shales. The acquisition includes 1,400 Boe/d of production. Backing out production at $80k per flowing, deal works out to $5,015/acre. Deal expected to close by end of December 2011.*	$5,016
JV	**12/23/2011**	**SD**	**Repsol**	$1,000MM	$250	$750	***Mississippian -*** *SD announced a JV agreement with Repsol for 250k (25% non-op WI in Extension Mississippian and 113.6K net acres (16% non-op WI) in the original Mississippian for $1B with $250MM up fron and $750MM in carry over three years. Discounting back total value and dividing by acreage comes to $2,400/acre. If you assume $1,250/acre for Extension, then value of original is ~$5,000/acre. Headline value comes in at $2,750/acre.*	$2,750

Source: Company data, Credit Suisse estimates.

North American Explorers Go Mainstream

We believe exposure to North American offshore explorers will be an increasingly compelling theme in 2012 and beyond

International exploration has been one of our key fall 2011 themes and will continue into 2012. Although historically most investors would associate offshore exploration with the European Independent E&P sector, we believe North American offshore explorers have become an compelling investment theme. We highlight CIE, KOS, HES, APC, NBL, EXXI, and NIKO as companies drilling material wells over the next 12 months. Key areas to watch for the North America Explorers include :

- **Pre-salt Angola:** With two industry successes in a row (and the third in total for the Angola Pre-salt) it is early but very encouraging times. Cobalt alone could have net unrisked mean reserves of over 5bn boe on its blocks. Rock quality is the key determinant of success; we should have the results of the first flow tests from Cobalt imminently. Although Cobalt shares have rallied by 50% since the announcement, unrisked potential is over $40/sh.
- **Ghana exploration is not over:** The recent step-out well proving larger resource potential at Teak (KOS, APC, TLW) and the HESS Paradise success are two recent examples of the resource upside potential of Ghana. Aside from an appraisal campaign in Deep Water Tano, further Teak appraisal, Cedrela and 3-5 wells in HESS block (Paradise Deep, Beech, Hickory), we may also get a validation of the value of exploration acreage from a HESS farm-down.
- **West Africa Transform Margin:** Although APC has had noncommercial discoveries in Sierra Leone (Venus and Mercury) and in Liberia (Montserrado-1 well), it was successful in proving a working hydrocarbon system. We are likely to hear more from APC and others over the next 12 months as they continue to drill several high impact wells over the next 12 months.
- **East Africa Natural Gas:** Deepwater East Africa will remain in focus over the next couple of years as an emerging gas province. In Mozambique, talks of a multitrain LNG development (up to six trains) are ongoing as APC/Cove and Eni/Galp continue exploration and appraisal activities. In particular, we await news of the ENI flow test, on a structure abutting APC's block—it could be a significant catalyst for the play.
- **South China Sea:** As we highlight in the Asia-Pac section, APC also has exposure to an emerging play in the South China Sea that could be significant.
- **Gulf of Mexico:** With the "permitorium" lifting, the industry is getting back to work, not only to appraise the significant number of recent discoveries (Lucius, Hadrian, Appomatoks, West Vito, etc) but returning to exploration. Within the NAM exploration group, key GoM wells include Phobos, Heidelberg, Vito, Ligurian, North Platte, Aegean, Ardennes.
- **Deep Shelf Gas:** While gas prices may be weak for some time, a new source of low break-even gas is emerging in the Deep Shelf. Blackbeard East could confirm the concept that deep gas bearing sands across the shelf are likely prospective across multiple structures. This could expose EXXI to more than 10 tcf of net gas potential (more than 1.5 billion barrels of oil equivalent).
- **Indonesia:** Thus far, Indonesia has been a disappointment despite having some of the largest offshore undrilled acreage in the world. We are expecting imminent well results from HESS (a multibillion gas giant in the Semai V block) and from NIKO. NIKO's main exploration catalyst is the expectation that first exploration wells offshore of Indonesia will commence some time between June, 2012 and August, 2012. Other

exploration results that could move the needle for NIKO are offshore of Trinidad in Block 2ab (1Q12).

- **Western Med Gas:** Since 2009, NBL and its partners have announced two world class natural gas discoveries offshore Israel at Tamar and Leviathan. In total, these discoveries have a gross mean resource potential of 26 tcf. On the basis of successful appraisal drilling, NBL estimates over 9 tcf of recoverable gas resources at Tamar. Following a second successful appraisal well at Leviathan, NBL raised its gross mean resource estimate to 17 tcf from 16 tcf. Given the high quality of the reservoir, NBL believes producing wells at Tamar and Leviathan will be able to flow at rates approaching 250 mmcf/d (40kboed!), comparable to East Africa. NBL is studying development plans with Floating LNG looking as the most viable development option for Leviathan gas. In addition, the company is conducting a significant exploration test at the Cyprus A-1 well, which is on trend with Leviathan. Early indications suggest NBL has found significant gas in Cyprus. In total, NBL has identified 12 prospects with unrisked resources potential exceed 20 tcf. The company is going to test a deep oil play concept in 2012 below the Leviathan gas field with significant potential (3.7 BBoe of unrisked potential resource).

Importantly, with exploration success under their belts, exploration-focused management teams with a good track record could pick up the institutional backing to unlock significant value over time.

Focus on Cobalt and the Pre-salt Angola

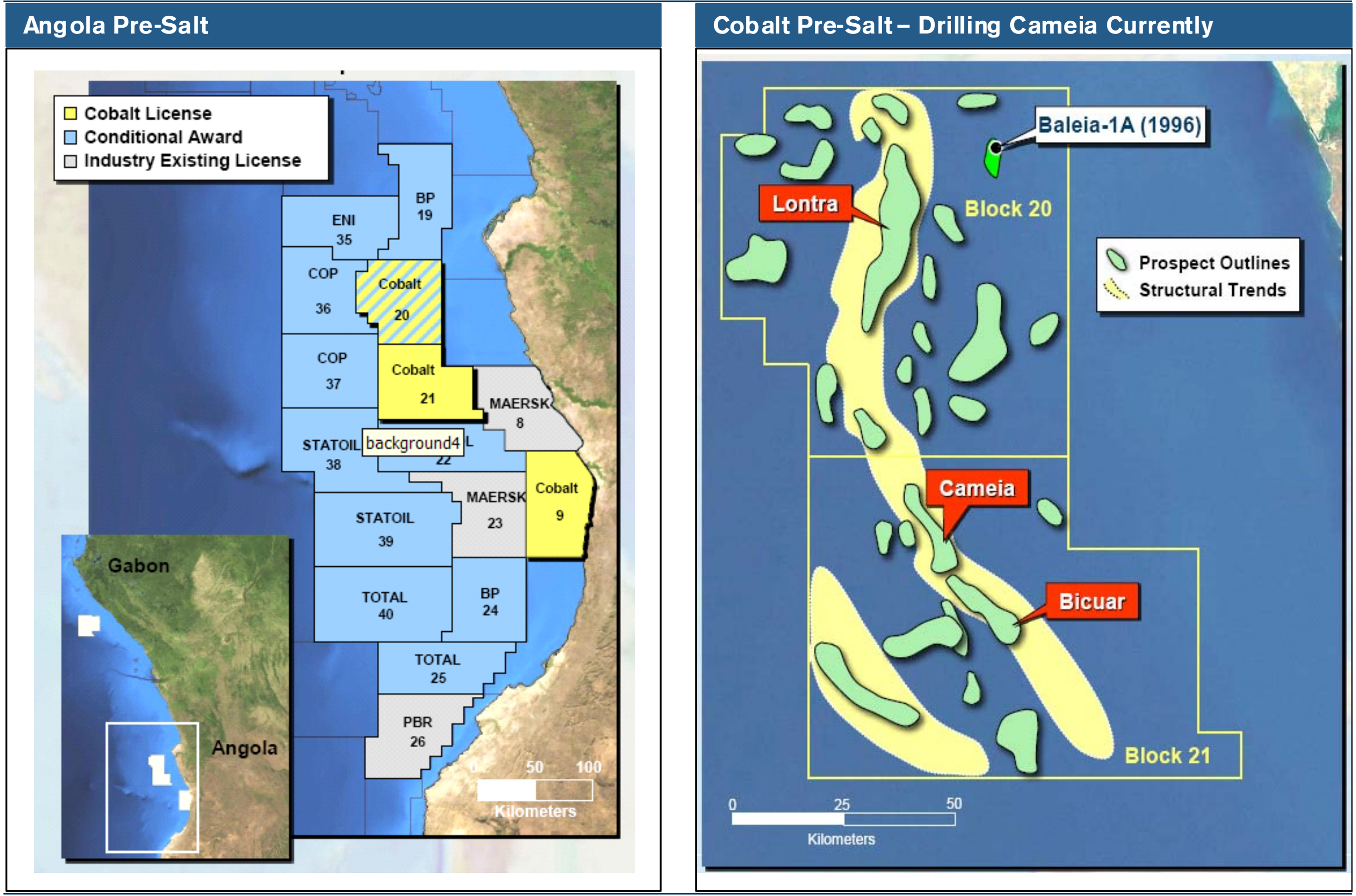
Over 5bn boe of gross unrisked 100% Pre-salt Angola resource places Cobalt firmly on the radar

Encouraging Results from Cameia well on Angola Pre-salt Block 21: CIE have hit target depth at Cameia and after an extensive series of logging tests have confirmed the “presence of hydrocarbons” and the results are “very encouraging”. One of the key issues with the Pre-salt Angola wells will be the rock quality in these deep reservoirs. CIE is conducting a well flow test and will release results in around a month. Once these are released, CIE and investors will be able to better value the Angola Pre-salt. Nevertheless its potential for CIE is significant (see chart of unrisked NAV upside over time below).

Formally Signed Block 20 PSC: Cobalt has finally signed Block 20. This is important as it contains the Lontra giant and unrisked net mean resource of 2.5bn boe overall. Indeed today’s well results from Cameia and from Baleia (back in 1996) support the case for hydrocarbon bearing reservoirs in the near vicinity. CIE is moving forward with the 4,200km seismic shoot on Block 20 and Lontra remains on track for a spud in 2013.

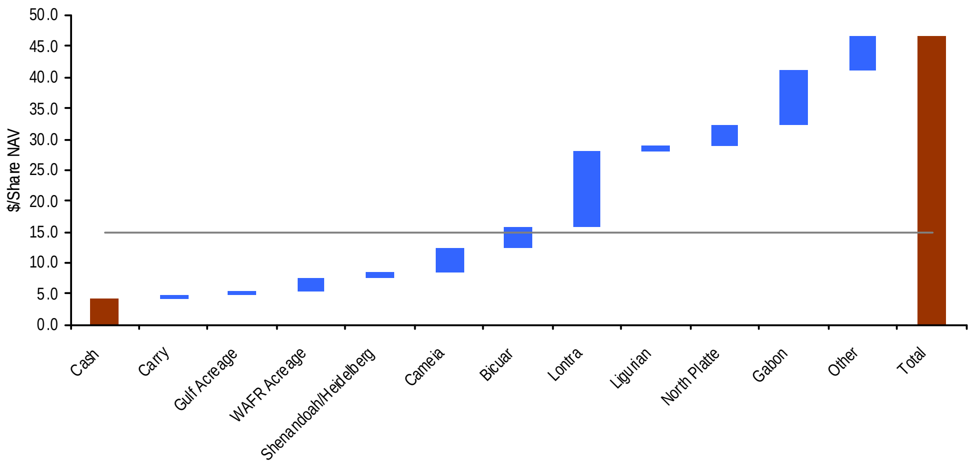
Potential positive read across from Maersk for Pre-salt Block 9 : Upstream Online have reported encouraging results for Maersk’s well in Block 23 near to CIE’s Block 9 prospect. CIE should finish the 3-D seismic in 1Q12. The data quality looks good and CIE hope to drill the first prospect before the end of 2012.

Exhibit 135: West Africa Exploration: Angola Pre-salt—Cobalt Currently Drilling Its First Target



Source: Company data, Credit Suisse estimates.

Exhibit 136: Cobalt Unrisked NAV Waterfall



Cobalt offers significant unrisked upside even after its recent move

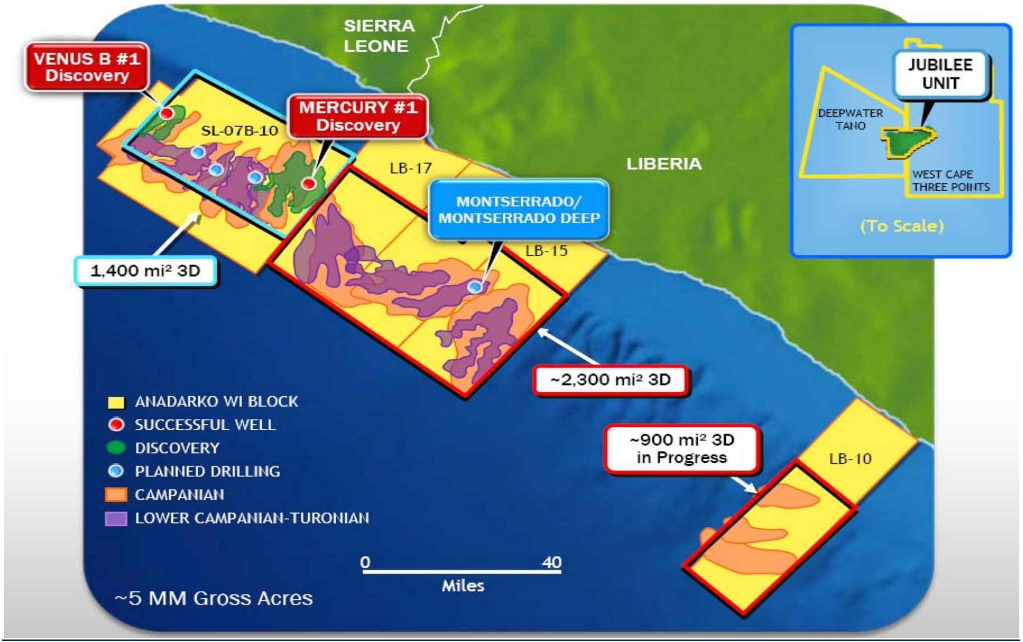
Source: Company data, Credit Suisse estimates.

APC Offers Good Exposure to West Africa, East Africa Gas, and South China Sea

Although Montserrado, offshore Liberia, was noncommercial, this is still very early days in extending Ghana play concepts along the West Africa coast. The drill ship has now moved to Sierra Leone to test the Jupiter prospect and drill the first Mercury appraisal well. APC also plans to remain very active in Ghana and Mozambique, with additional drilling activities in Côte d'Ivoire, Brazil and China in 2012.

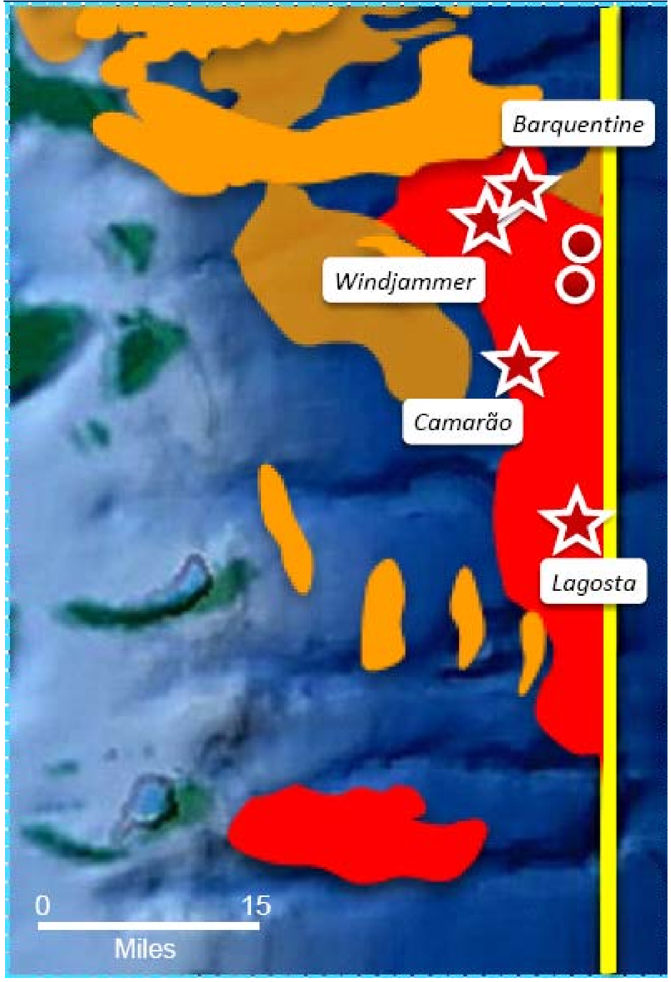
Exhibit 137: APC Testing Liberia, Sierra Leone, Cote D'Ivoire

Large multi-hundred barrel prospects being targeted by APC, Tullow, CVX in Sierra Leone, Liberia and Cote D'Ivoire in 2012



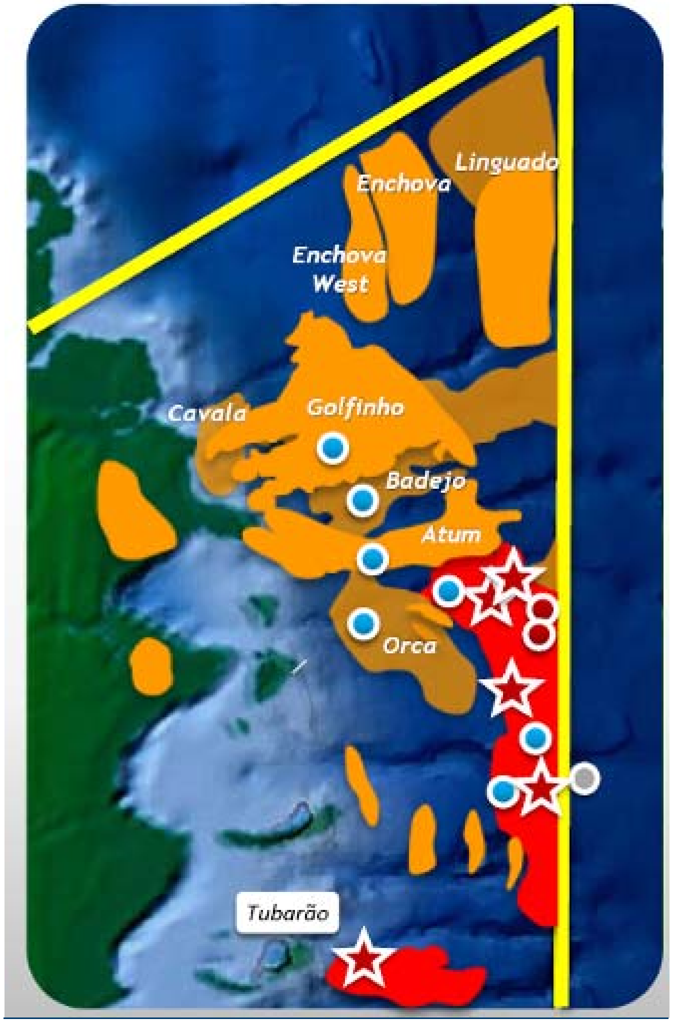
Source: APC.

Exhibit 138: **Mozambique Gas : 15-30 TCF Gross Recoverable Reserves in the Discovery Area**



Source: Company data, Credit Suisse estimates.

Exhibit 139: **Mozambique Gas : Substantial Prospects and Leads Still to Drill**



Source: Company data, Credit Suisse estimates.

Lots to Play for Still in Ghana

Teak appraisal, Deepwater Tano exploration and HESS drilling program are the wells to watch in 2012 in Ghana

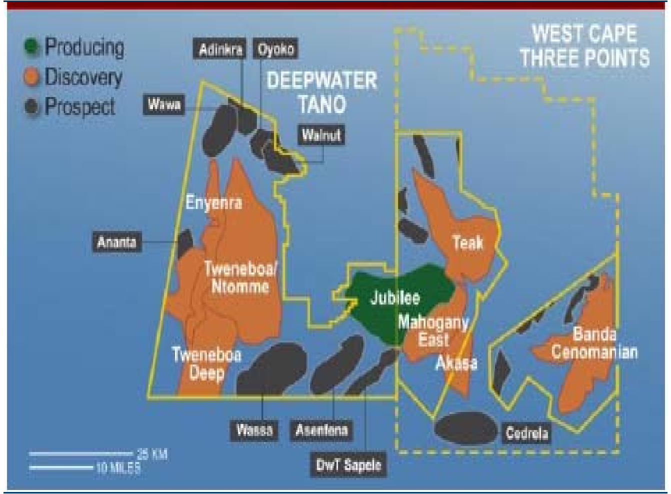
Although investor focus has shifted toward Guyana, East Africa and the Angola Pre-salt, there is still more to play for in Ghana. Notably we highlight

- **West Cape Three Points Teak Appraisal:** The Teak-3A appraisal well confirmed a northern extension of the Teak discovery approximately 4 kilometers (2.5 miles) north of Teak-1 and encountered approximately 35 meters (115 feet) of hydrocarbons in multiple good-quality reservoirs.
- **West Cape Three Points Cedrela 1:** Due to a damaged rig, KOS declared force majeure on this well, aiming to hold the acreage until a replacement rig could be sought.
- **Deepwater Tano Exploration Phase—Tweneboa Deep:** Tullow aims to test *“ the large turbidite fans clearly evident in 3D seismic data below Tweneboa. These large turbidite fans, Turonian Deep, and the deeper Cenomanian Deep fans, have been derisked by recent wells offshore Ghana, which encountered thick sands in this stratigraphic interval”.*

- **Deepwater Tano Exploration Phase—Wawa, Wassa, Sapele:** Tullow plans to drill the Wawa prospect which lies immediately up-dip from the Enyenra oil discovery. The Sapele prospect, adjacent to the Jubilee field, and other new leads emerging from detailed seismic interpretations in this area, e.g., Wawa, are also strong candidates for Tullow's 2012 exploration program, offshore Ghana.
- **Albian:** This contributed to the HESS net pay at Paradise. Structures such as Teak/Jubilee could have Albian layers beneath them. There will likely be Albian on the Deepwater Tano block also.
- **HESS:** To the south of Deepwater Tano and West Cape Three Points, HESS discovered 490 feet of net pay at Paradise. HESS has organized a rig to arrive in Feb 2012 which has 3-5 drilling slots. HESS plans to drill Paradise Deep, Hickory and Beech and may also test a southern extension of Tweneboa Deep before it has to decide on acreage relinquishment in 2Q13.

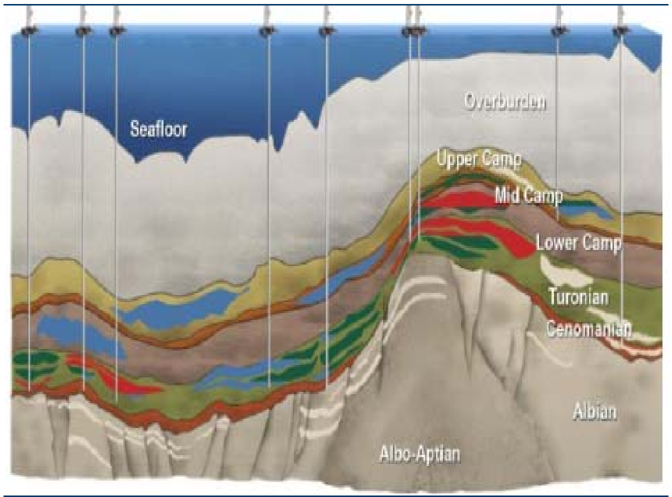
Ghana exploration is not over yet.

Exhibit 140: **Exploration Upside in Ghana (Grey Color Prospects)**



Source: KOS.

Exhibit 141: **Ghana—Geologic Layers**



Source: KOS.

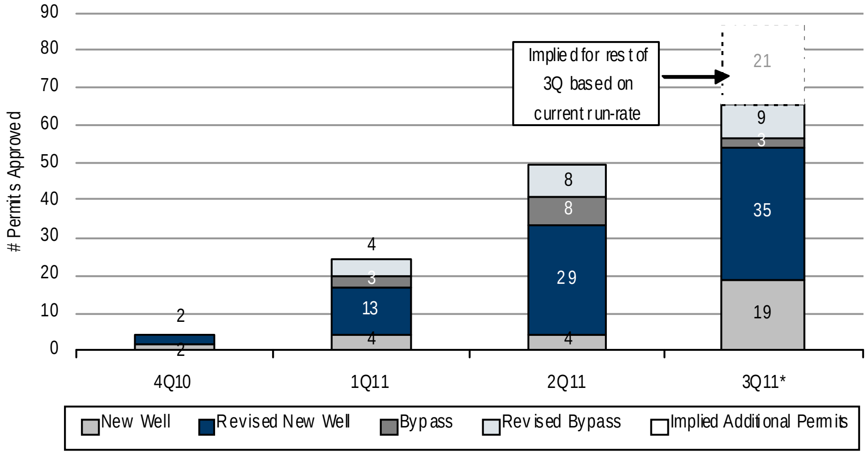
Positive Implication for Offshore Service/Deepwater Rigs

The success in West Africa and French Guiana has a positive impact for offshore service/rig demand at the margin (though smaller than Brazil and many of these basins are in their early days). As important, the pace of activity is increasing in the Gulf of Mexico. We estimate that Gulf of Mexico reserves in appraisal and discovery equal the current producing reserves in the Gulf today. The industry is itching to appraise and bring these reserves into production more quickly once the BOEMRE permitting process is running smoothly. New geologic concepts are also increasing interest in potential lease rounds also.

Exhibit 142: Deepwater Permits Increasing

Deepwater permitting is increasing in the Gulf

Exhibit 1: Deepwater Permits (=500 ft. W.D.) approved since moratorium end



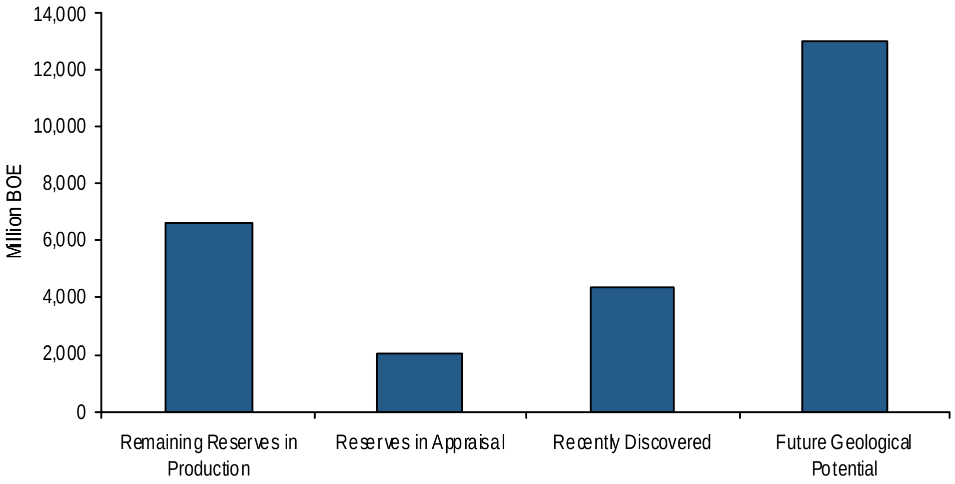
Source: BOEMRE

*Note: Excludes sidetrack permits, *3Q11 actual permits are through 9/15/11*

Source: Company data, Credit Suisse estimates.

Exhibit 143: GoM—Reserves in Appraisal and Discovery Equal Current Producing Reserves

There is a large amount of existing GoM resource to develop



Source: Company data, Credit Suisse estimates.

Oilfield Services in 2012: You Should Pay Less for That Stock (but More than Today's Price!)

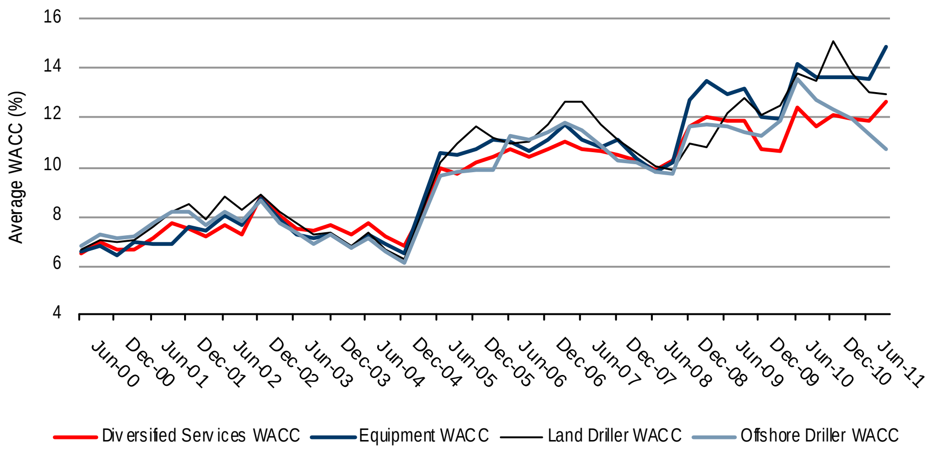
We think growth fundamentals suggest value, even if on lower target multiples

We think it makes sense that OFS stocks should trade at lower multiples than they have in prior cycles. This is primarily due to equity markets and risk premiums, which have raised their cost of capital, but we acknowledge operational risks for the sector as well. **However, we believe shares should appreciate from current levels, because the current focus on margins and other operating challenges ignore the longer term potential for revenue, earnings and cash flow growth over the coming cycle.** Further, we believe there are steps the companies are taking and can take to minimize volatility and unlock shareholder value and in turn lower their capital costs.

Two Categories of Risks Currently: 1) in Operations and 2) Equity-Markets

OFS has two, in part related, challenges currently: 1) there is apparent risk in operations that can impact 2012 earnings (and plausibly beyond); and 2) the cost of capital for the sector (WACC) has nearly doubled since 2000. See Exhibit 144. This latter challenge is a function of sector volatility (higher Beta), but also of a rising equity risk premium.

Exhibit 144: **Average WACC across Coverage (2Q00-3Q11)**



Source: Company data, Bloomberg, and Credit Suisse estimates

We think the risks are concentrated on the execution (and not the demand) side.
In our view, the most important current operating challenges are concentrated on the cost side; we address some of these in the "OFS Minefield" section below as well as for the offshore drillers specifically in a companion section that follows this one.

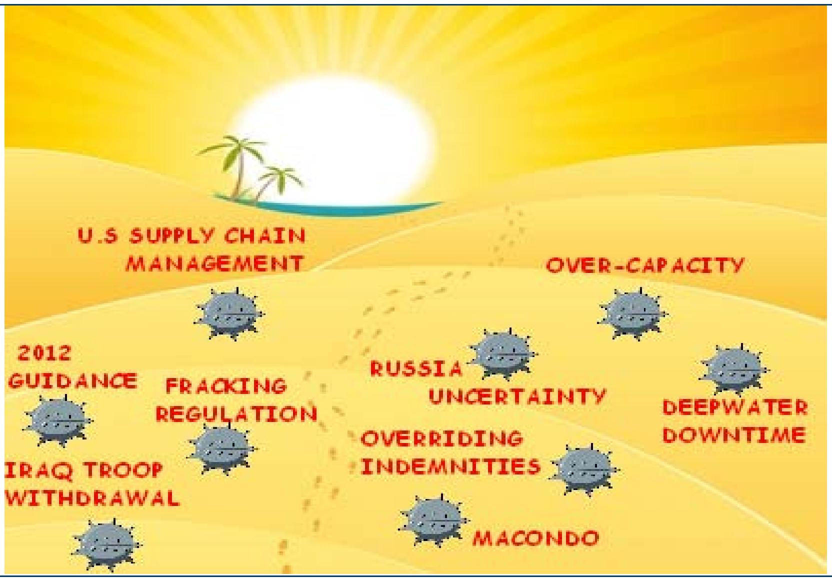
In fact, it is our confidence in demand that argues for multiple appreciation in shares.
There are indeed risks to the demand side, including 1) the Middle East/North Africa region, in our view, given political uncertainty and 2) the "slow bleed" of hydraulic fracturing regulatory risk that could impact demand in the US, Australia and elsewhere. However, we contend that it is the demand side that argues for multiple appreciation in shares. The US most importantly is establishing itself as a less volatile market. And globally, the work that looms related to deepwater and unconventional gas development should in most cases spur stronger, higher end growth.

OFS can take steps to help itself and lower its WACC.
We sense that the companies can help address the concerns that are contributing to higher cost of capital. These steps can include: 1) firming up contract protections in US

fracturing, 2) growing production exposure (e.g., artificial lift, chemical injection, fluid analysis and field management), 3) strengthening logistical capabilities to derisk, 4) Relever balance sheets and 5) arguably slow the pace of market share strategies.

Challenges in Oilfield Services—The OFS 'Minefield'

Exhibit 145: The OFS Minefield on the Path to Growth



Source: Dreamstime LLC., Clker, Credit Suisse.

A weaker than expected share performance in 2011 can partly be ascribed to the OFS minefield of political and operational issues that need to be overcome

By 4Q11, it was impossible to get away from the litany of challenges faced by OFS today. Most are commonplace and in our view, transitory, including (e.g. wage pressure) and some are symptomatic of strong demand (supply chain management in the US) or requirements to expand capacity to handle future demand. We also accept the argument that there is more competition across the space than at least at times in the past.

There are, however, challenges that have at least some tail risk of "upending" OFS, including (1) the US government in effect overriding indemnifications protecting contractors in Macondo contracts and (2) the Environmental Protection Agency (EPA) assuming regulatory authority over hydraulic fracturing (although we expect this only in 2014). We review some of these challenges below.

Supply Chain Management

US service providers continue to experience supply chain challenges primarily in US hydraulic fracturing operations. The challenges center on accessing adequate raw materials (sand, acid) for massive hydraulic fracturing jobs, including an increasing proportion of 24-hour/7 day per week operation.

Supply chain has been among the challenges faced by North American service providers given the dramatic ramp in activity in 2011. We generally expect that a more modest growth pace should allow firms to "catch up". However, we remind investors of our caution expressed through most of this year regarding adequate availability of fluid ends in 2012; we continue to suspect lining up adequate spare fluid ends (and other consumable equipment parts) to trip up some frac service providers at different points in 2012.

2012 Guidance Risk

We believe there remains some 2012 earnings risk within OFS. International service operations face prospects of slower-than-expected margin growth, weighed down by modest (i.e., not more frenetic) revenue growth, continued pricing pressure, and investments made to prepare for growth in key countries.

Deepwater Downtime (Deepwater Drillers)

Deepwater drillers are experiencing more unanticipated downtime than historical norms, some attributable to post-Macondo era sensitivity and some, we think, to challenges experienced more selectively (for example, by RIG) related to its older fleet. Please see further discussion of this topic in our companion note that follows.

International Political Uncertainty

The political landscape for 2012 feels less certain in the Middle East/North Africa in light of Egyptian elections, a still uncertain outlook in Libya, and the US troop withdrawal from Iraq. We are not adjusting our estimates for growth in these regions, but there is clearly an element of risk to our forecasts. We note also with interest the political activism in Russia. We are not saying we expect a different outcome than Prime Minister Putin reassuming the presidency, but we believe OFS companies have in part grounded their optimism regarding growth in Russia next year on political stability and that would appear marginally less assured now than a month ago.

The EPA Potentially Regulating US Hydraulic Fracturing

The EPA's draft report in early December of its Pavillion, WY ground water contamination study was noteworthy in that the EPA claims that it can deduce that there was fracturing fluid migration from frac job(s) at 370 meters depth up to a test well of 235 meters through sandstone. There are many site-specific circumstances here, but we think the finding disrupts a general industry claim that frack fluid migration is much more limited than this. And as such, it incrementally ads to the risk that the EPA may determine the need for and seek the authority to regulate hydraulic fracturing when its fuller study is completed in 2013 and final papers are issued in 2014.

Macondo Aftermath

The recertification of BoPs and the heightened sensitivity to the conditions of subsea systems have taken their toll on productivity and earnings and threaten to modestly do so going forward. But we are more concerned with the risk of penalties from the US government that may be levied on the service industry. Such penalties can come in one or both of two ways. First, in October the Bureau of Safety and Environmental Enforcement (BSEE) issued violations for "Incidents of Non-Compliance" (INCs) to HAL and RIG. This was the first time the Department of the Interior issued INCs to contractors (as opposed to the well operator); the BSEE noted that the decision reflected the severity of the incident. Although unclear, this leads us to question the value of the contractual indemnities between BP and HAL and BP and RIG. Second, the Department of Justice's civil suits against various parties including RIG under the Clean Water Act (CWA) remain outstanding. *Please see the Appendix to this note for further Macondo legal discussion.*

Rising Cost of Capital for OFS

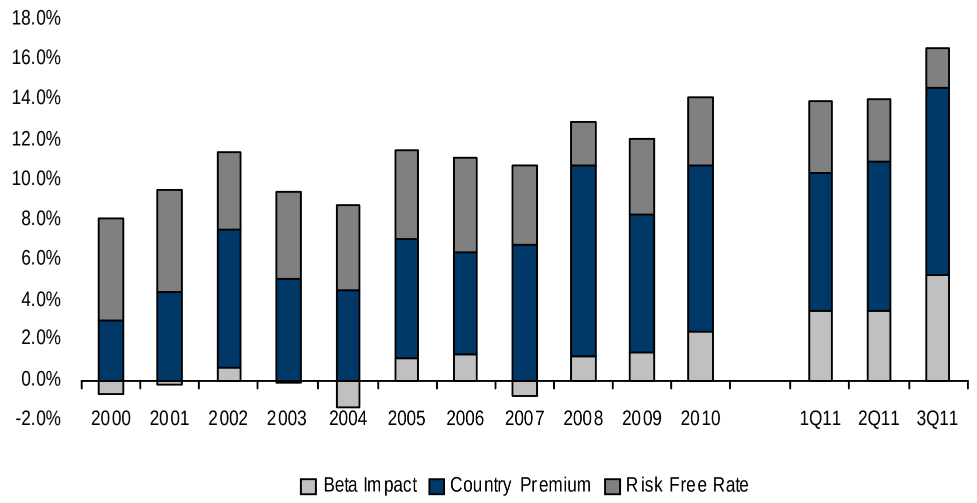
The WACC embedded in the OFS group has increased 87% since 2000

The cost of capital for twenty names in our OFS universe is 87% higher on average than it was in 2000 and in many cases has doubled. This is a function of several factors, some having nothing to do with OFS, but rather the market: equity risk premium, country risk and volatility have all spiked.

We use HAL purely for illustration purposes. Its WACC, per calculations made by Bloomberg, had risen to 14.8% by 3Q11 from 6.9% in 2000. The increase was NOT attributable to the Risk Free Rate, which Bloomberg calculates as 1.92% as of 3Q11 versus 5.11% as of 2000. And it was only very modestly driven by a greater weighting in its capital structure of Equity versus Debt—the calculated weighting of equity was 88% as of 3Q11 versus 85% in 2000.

Rather, the more important reason for the WACC increase is that the cost of equity has risen to 16.5% as of 3Q11 from 7.5% in 2000. This cost of equity increase was due to both an increase in the country premium—to 9.4% in 3Q11 from 2.9% in 2000—and HAL's Beta, which had risen to 1.55 as of 3Q11 from 0.80 in 2000. See Exhibit 146.

Exhibit 146: **HAL—Cost of Equity (2000-3Q11)**



Source: Bloomberg.

What Companies Can Do: Lower Risk, Delever

Addressing increased (perceptions of) equity market risk is clearly outside of OFS company control. But we do sense that the companies can help address the concerns that are partially resulting in their higher cost of capital.

Contracts that have some downside price protection and greater exposure to production-oriented services could reduce risk perceptions

1. Take a tough line on contracts
With the amount of contracting that has taken place for hydraulic fracturing services and that is underwriting newbuild contracts for land rigs in the US, OFS is likely operating with more contractual backing than it ever has. Yet it is clear that in the case of hydraulic fracturing contracts, there is the perception—even within the industry—that the contracts will do little to protect pricing for that equipment in a downturn. Rig contracts went through similar periods of uncertainty, but first offshore and then onshore drilling contractors held the line on contracts through recent downturns, and have cemented confidence in those contracts. Having service contractors do the same if pressed—which we admit we are not looking for any time soon—should help dampen perceptions of risk in the US service market.

Separately, we would look to offshore drilling contractors to pursue greater risk sharing for unplanned downtime for rigs. The aftermath of the Macondo disaster has led to significant sensitivity related to subsea systems. Anecdotal evidence suggests that operations are being halted anytime there is any question about even a backup system. That may be prudent in light of the risks of deepwater drilling. However, it has created a commercial burden on offshore contract drillers that is contributing to earnings risk.

2. Grow production exposure (versus exploration or development-related exposure)
OFS revenue remains dominated by drilling and completion activities related to exploration and development drilling. Yet as the oilfield industry continues to consider how to manage declining fields and to seek to raise ultimate recovery factors, the opportunities associated with production are expected to grow. There is, of course, considerable overlap in more production-oriented activity with what our companies do today, namely more infield drilling and redevelopment of brownfields. But we suspect more exposure to distinctly production-related services, including artificial lift, chemical injection, fluid analysis, and field management, will give visibility on a more consistent growth profile.

3. Improve logistics to lower execution risk

The dramatic volume growth of hydraulic fracturing in NAM and the challenges associated with deepwater rig subsea systems have, surprisingly, highlighted a similar need/competency for logistical excellence. Avoiding the lost time, whether because companies are waiting on equipment or sand from vendors, can, as we have seen recently, dramatically help near term earnings outlooks.

4. Relever balance sheets (and return cash to shareholders)

Releveraging and returning excess cash to shareholders would reduce WACC

Although the increase in cost of capital stems largely from more expensive equity, as opposed to a dramatic shift in leverage, OFS companies can still recapitalize balance sheets to raise net debt and thereby lower their cost of funds while returning cash to shareholders. We acknowledge that having less debt was generally helpful to share performance in 2011, but we submit that longer term, the benefits to share performance from a lower WACC would more than outweigh that “safety net.”

We offer the following math as an indication of the potential from the companies’ and investors’ point of view of “relevering.” If the eight companies under coverage in the diversified services and equipment segments were to use cash/debt to repurchase enough of their shares to lower the calculated WACC by 100 bps, the group would have bought back an average of 7.5% of their shares, generating an average of 7% accretion to their 2013 earnings and still be left with an average net debt to cap ratio of 20%. See Exhibit 147. If instead the same group used cash/debt to offer a special dividend, but again changed the equity/debt mix to lower their WACCs by 100 bps, they could offer a special dividend that averaged a 9.7% yield. See Exhibit 148.

Exhibit 147: EPS Accretion and Resulting Debt/Cap from Share Repurchase

Ticker	WACC [1]	% of Shares Outstanding Repurchased [2]	CS '12 EPS	CS '13 EPS	% Change from Current 2013 EPS	Current Net Debt/Cap	Pro-Forma Net Debt/Cap
BHI	12.91%	9.0%	$5.60	$6.90	8.7%	16%	23%
HAL	14.75%	8.3%	$4.25	$5.50	8.4%	10%	22%
SLB	12.70%	8.5%	$4.70	$6.00	7.2%	13%	26%
WFT	9.68%	8.1%	$1.45	$2.05	7.8%	42%	45%
CAM	13.33%	8.2%	$3.50	$4.75	7.2%	1%	15%
FTI	12.85%	6.5%	$2.15	$2.55	5.5%	9%	35%
NOV	15.19%	5.2%	$5.60	$6.00	7.0%	-19%	-10%
OII	14.09%	6.1%	$2.45	$2.95	5.4%	-11%	8%
Average		7.5%			7.1%		20%

(1) As of 3Q11

(2) Solved for repurchase quantity in order to lower WACC by 100 bps by lowering Equity weighting

Source: Company data, Credit Suisse estimates.

Exhibit 148: Special Dividend Yield if Use Dividend to Raise Debt Weighting

	Increase in Debt	New Debt Level	Shares Out	Share Price	Special Dividend	Special Dividend Yield
BHI	$2,461	$6,361	439	$49.81	$5.61	11.3%
HAL	$3,196	$7,020	925	$33.49	$3.46	10.3%
SLB	$9,825	$21,308	1357	$68.49	$7.24	10.6%
WFT	$1,722	$9,338	760	$14.31	$2.27	15.8%
CAM	$1,286	$2,873	247	$49.96	$5.20	10.4%
FTI	$932	$1,462	243	$51.95	$3.83	7.4%
NOV	$1,635	$2,147	425	$68.67	$3.85	5.6%
OII	$332	$332	109	$46.79	$3.05	6.5%
Average						9.7%

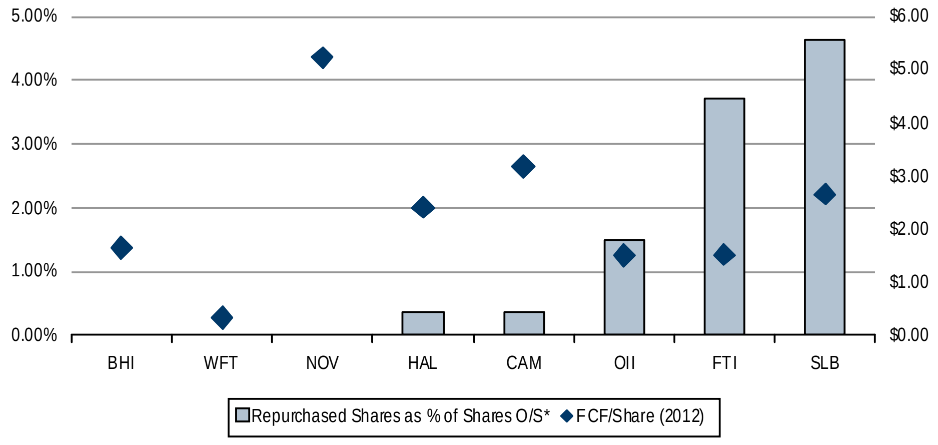
Note: Debt and Equity structure are based on 3Q11 data and Bloomberg inputs. "New Debt Level" is based off a 100bps decline in the respective companies' WACC.

Source: Bloomberg, Company data, Credit Suisse estimates.

Share repurchases by this group have been limited over the past three years (seeExhibit 149), as managements have had to live through the market correction of 2008 and an uncertain recovery. We note that we respect managements' conservatism. Yet we expect FCF to improve markedly starting in 2012, and we believe our view is consistent with the companies' (at least directionally). More aggressive share repurchase or dividend policies would, we believe, help persuade investors of managements' conviction regarding growth potential as well as manage to a lower cost funding base.

FCF set to expand in 2012

Exhibit 149: Share Repurchases, 2009-3Q11



"Repurchased Shares" are those shares repurchased during 2009-2011 YTD

Source: Company data.

5. Slow the pace of a market share gain strategy

Companies' efforts to raise their long-term market share—we offer HAL and PDS as notable examples currently under our coverage—are raising questions among investors regarding the pricing and margin implications for them and their direct competitors of those efforts. More aggressive growth clearly entails risk. In HAL's case, it includes maintaining its presence in some regions through downturns and adding incremental capital/capability into some emerging regions, including Iraq. In PDS' case, the company's ability to execute on at least three newbuilds per month in 2012 and attempts to grow its service lines are raising the questions.

We admit this last one is controversial. Capable (and visionary) companies should take the opportunity to sustainably grow faster than peers and they should be rewarded for it upon successful execution. However, in the interim—and that may prove to be an extended interim—the questions raised about the impact of such a strategy on margins and/or the ability to execute are expected to continue to weigh on share prices (multiples).

Appendix: An Update on the Status of Post-Macondo Legal Events

Trial Plaintiffs Lawsuits

Starting on February 27, 2012, the Honorable Judge Carl Barbier, of the United States District Court for the Eastern District of Louisiana, will preside over the Multi-District Litigation (MDL 2179) trial. The MDL will package together all pending civil lawsuits filed throughout the Gulf Coast region (US technically) against BP, its operating partners, HAL, RIG, and CAM.

There are three phases to the trial. The first will focus on causes of the blowout and explosion to determine which companies must share the cost of billions of dollars in economic and property damage, which BP has so far been paying alone. In the second, liability by the parties will be assessed. This phase will also determine how much oil and gas was spilled in the Gulf of Mexico. The third phase will settle remaining liability issues, including claims related to efforts to contain and clean up the spill.

We believe the government investigations should weigh heavily on the judge's views. The BOEMRE and Coast Guard’s joint Panel report, released in September 2011, concluded that the central cause of the blowout was failure of the cement barrier in the production casing string. The reasons for the failure are unknown, although the Panel concluded that likely causes were (1) the swapping of cement and drilling mud in the shoe track, (2) contamination of the shoe track cement, (3) pumping the cement past the target location (over-displacement).

Several of the Parties Have Already Settled with BP

Of the parties involved, APC, Moex, CAM and WFT have settled with BP. In these settlements, e.g., with CAM “*BP's indemnity excludes civil, criminal or administrative fines and penalties, claims for punitive damages, and certain other claims*.” We note that with CAM's settlement, we imagine its challenge of the trial format—arguing instead that a jury trial was appropriate under the federal Outer Continental Shelf Lands Act—is no longer relevant following its $250 million purchase of indemnification on Friday, December 16.

Oil Pollution Act

BP, APC, Transocean, and MOEX are responsible parties under OPA. Transocean claims BP was negligent in well operations, which BP is disputing. Transocean has a contractual indemnity with BP—BP asserts Transocean was negligent both in its operation of the Deepwater Horizon drill ship and in its well control. As a reminder, OPA provides for individual economic losses, business economic losses, federal state and local damages (e.g., cleanup costs, lost government revenues, and costs of additional public services) and an assessment for Natural Resource Damages.

Department of Justice and CWA

Meanwhile, still outstanding is the civil lawsuit filed by the DoJ for violations of the Clean Water Act (CWA), originally filed on December 15, 2010. The defendants named are BP, Anadarko, MOEX Offshore 2007 LLC, Triton Asset Leasing GMbH, RIG, and QBE Underwriting Ltd., Lloyd’s Syndicate 1036. (Note that HAL and CAM are not among the defendants.)

Federal law imposes civil penalties, under the Clean Water Act, against those who unlawfully discharge oil into and upon the navigable waters of the United States and adjoining shorelines, into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act. Polluters are strictly liable under this Act, with penalties based in part on the number of barrels of oil discharged. The United States thus also seeks in this action the imposition of the Clean Water Act civil penalties for each barrel of oil that the Defendants discharged into the Gulf of Mexico.

CWA was designed to deter polluters and appears to have a low burden of proof. As we understand it, proving guilt in a CWA case involves establishing, in most jurisdictions, that the party was an owner or responsible for the operations that gave rise to the incident—in this case drilling the well—and not that a company did something "wrong" that specifically resulted in the oil spill.

With the modifications to CWA that followed the Exxon Valdez spill, strict liability penalties can be up to $1,100 per spilt, unrecovered, barrel—estimated in the Macondo incident to be 4MM barrels (though quantification will be determined in the MDL 2179 court case). With gross negligence the fine can be up to $4,300/bbl. Liability is "Joint and Several" and thus each named party may be subject to this maximum penalty. However, there is significant judicial leeway to account for the seriousness of the violation, the degree of success of efforts to clean up and to compensate affected parties.

We note, however, that the financial risk is smaller than if the DoJ chooses to pursue a criminal suit. With criminal conviction, under the Alternative Fines Act, a fine of up to twice the economic loss can be levied. At this point, criminal preparations are ongoing but no suit has been filed.

HAL (Cement Services Contractor)

Like RIG, HAL also claims BP was negligent in its well operations and has a contractual indemnity with BP. BP asserts HAL was negligent in its operations and mislead BP as to cement operations. HAL has also filed claims regarding an alleged higher, undisclosed hydrocarbon zone.

Until the trial is concluded, uncertainty will remain about the risks implict in offshore service contracts in the Gulf of Mexico and how the industry will manage risk-reward with its contractors in future.

Downtime Drag Still Relevant for Offshore Drillers

As pertains across Oilfield Services (see our preceding broader OFS piece), the Offshore Drilling segment appears to have solid demand, but carries risk to 2012 earnings, in the case of offshore drillers largely due to greater than expected rig downtime.

Downtime was a significant issue in 2011 but should be better factored into 2012 EPS, though there are still areas for concern

It is important to note that we expect the downtime issue to be less pronounced in 2012 than it was in 2011, when estimates were lowered by 78% for RIG, 59% for NE, and 43% for RDC. (See Exhibit 153.) The companies are offering greater visibility on expected downtime (with RIG being the most important case in point), and we believe the Blowout Preventer (BoP) recertification process that followed the Macondo disaster of 2010 has been largely completed.

It is also worth reminding that if 2012 earnings downside risk is more modest, then it is unlikely to be the most important determinant for share performance. Instead, we submit that if dayrates continue to move higher, it should raise longer-term perceptions of earnings power/asset value. We remain supportive of ESV and NE on this thesis.

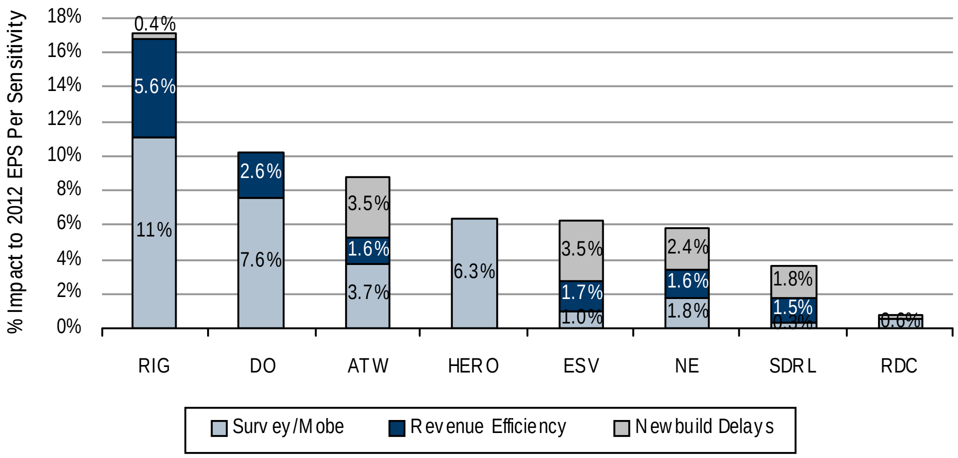
However, this earnings risk isn't irrelevant and even if the drillers are giving investors more insight into downtime, there are several areas of concern, including (1) imperfect visibility on planned downtime, (2) newbuilds, and (3) the still "hypersensitive" deepwater/subsea systems environment.

To illustrate, if our offshore drillers were to suffer from modestly higher levels of downtime in all three categories, we can envision anywhere from 6% to 17% EPS "risk" for six of the eight under coverage. See Exhibit 150.

We remain below the Street for 2012 EPS

We believe we are somewhat more conservative in our assessment of downtime risk than the consensus, which in part explains why we are on average 6% below the Street on 2012 EPS estimates. We apply downtime assumptions on a case-by-case basis—we give DO, ESV, and ATW more benefit of the doubt based on their strong track records (our below consensus estimate for DO in 2012 is based on lower revenue expectations as mid-water rigs transition away from Brazil) and burden RIG and NE relatively more.

Exhibit 150: 2012 EPS Sensitivities under Higher Downtime Assumptions



Note: adds 2 weeks of downtime per floater and 1 week per jackup related to planned yard time/contract prep; reduces utilization by 100 bps for contracted rigs (there is no change to uncontracted rigs) and adds 1 month of delay to start-ups of new rigs.

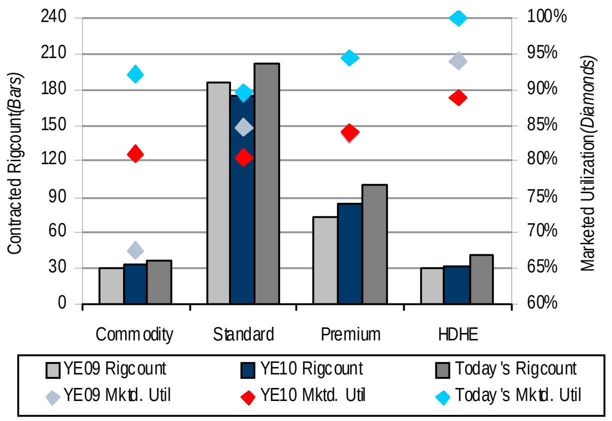
Source: Company data, Credit Suisse estimates.

Fundamentals improved nicely over 2011 and we expect them to remain favorable.

Pricing gains should continue into 2012

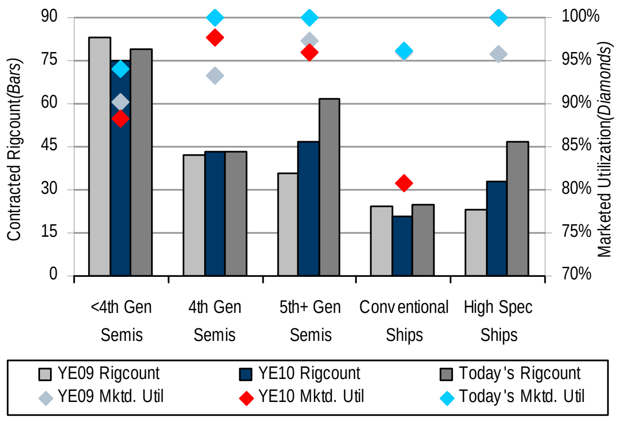
We expect supply-demand fundamentals to continue to improve among the different offshore driller asset classes given the healthy commodity price and helped by a relatively slow year for rig deliveries in 2012 (i.e., less competition from supply adds). **Exhibit 151** (jackups) and **Exhibit 152** (floating rigs) highlight year-end 2009, year-end 2010, and current contracted rigcounts (*see bars*) and marketed utilization (*see floating diamonds*) for the different rig types within those asset classes. In each case, the contracted rigcount and marketed utilization rose over the course of 2011, helping drive pricing gains across asset classes that should continue into 2012 as well.

Exhibit 151: YE09, YE10, Today JU Rigcount & Mktd. Util.



Source: ODS-Petrodata, Credit Suisse estimates.

Exhibit 152: YE09, YE10, Today Float. Rigcount & Mktd. Util

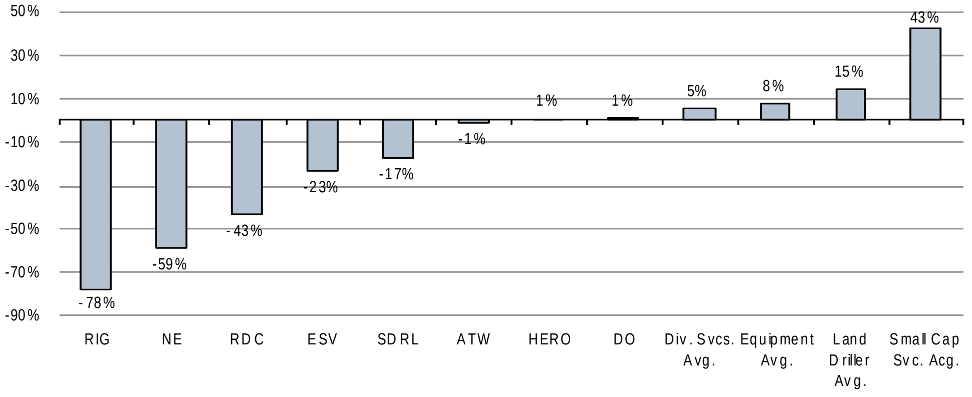


Source: ODS-Petrodata, Credit Suisse estimates.

But downtime has been the issue.

However, despite improving trends throughout 2011, we saw notable downward estimate revisions from the likes of RIG, with its headline making operational challenges in 3Q11, and NE but also to a lesser extent RDC and ESV. In fact, estimate revisions for the offshore drillers were down for 5 of the 8 companies under coverage and flat for the other 3, while they were up for other key segments within oilfield services.

Exhibit 153: 2011 Estimate Revisions since YE10



Source: Bloomberg, Credit Suisse estimates.

**RDC impacted by sale of LeTourneau, land drilling businesses, but we note a ~30% reduction in 2011. Consensus EPS since mid-Aug, at which point 'clean' guidance had been given*

Downtime has increased post-Macondo and also on newbuild start-ups

The pressure on earnings has come primarily from downtime—both more unanticipated zero revenue days and delays/overruns on planned shipyard stays. We note this latter issue is generally a double whammy, with the hit to top-line associated with a rig not 'working' often compounded by higher associated opex related to the repair and maintenance (R&M) work. To elaborate on the 'many-headed hydra' that is downtime, we parse out the three kinds.

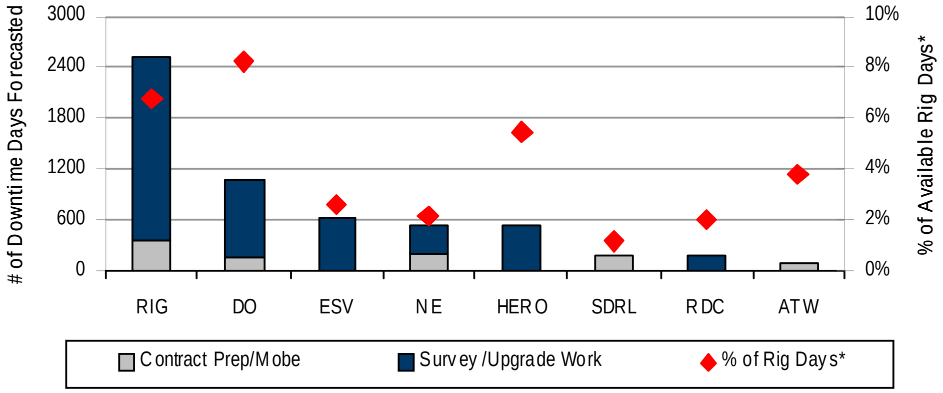
(1) Unanticipated downtime, which has become more of an issue in our post-Macondo world as operators (and perhaps to some extent contractors) bring a "zero tolerance" mindset to the rig floor and particularly subsea systems, meaning sudden work stoppages as OEM/equipment experts are brought-in to address even seemingly minor issues or redundancy/backup systems; **(2)** risk to timely newbuild start-ups or revenue efficiency once contracted, and **(3)** planned yard stays, which can result in vendor equipment delays and/or detection of issues that will require more time.

We think investors have come to at least accept more volatility in earnings from downtime, but **we suspect downtime risk will continue to weigh on earnings as we go into 2012**. This in turn can weigh on multiples until we see signs that operators have a firmer grip on operations.

1. Planned Downtime

Planned downtime days for 2012, based on what the companies have disclosed so far, ranges from 1% of available rig days for SDRL to 8.3% for DO, for which 2012 is a busy survey year, and 6.7% for RIG (Exhibit 154).

Exhibit 154: **Estimated Downtime Days and as % of Rig Days* in 2012**



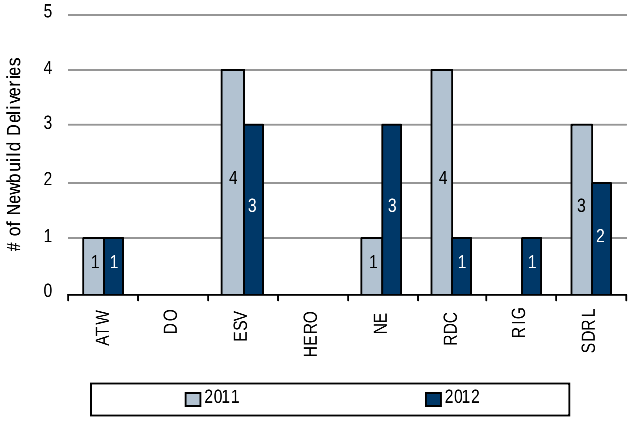
Source: Company data, Credit Suisse estimates.

Notes: (1) 'rig days' captures rigs marketed as of YE11 (i.e. does not assume reactivations), (2) data does not adjust for <100% owned rigs, (3) HERO data is for jackups only, (4) ATW data is for FY12 (Sept. end).

2. Newbuild Start-ups

Another area that can pose risk relates to newbuild start-ups. Although significant delivery delay risk does not appear meaningful at this point, we note the potential for some delay given all the moving parts that come with a new rig, including mobilization, contract prep, acceptance testing and where applicable customs and importation. ESV and NE have the most risk here given 3 newbuilds will be starting up operations for each company in 2012. See Exhibit 155 and Exhibit 156.

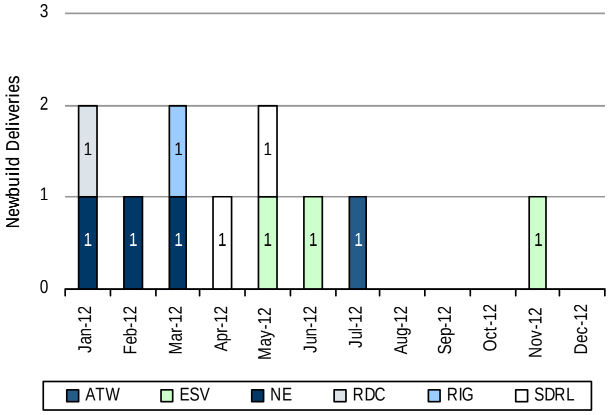
Exhibit 155: **Newbuilds per Company: 2011 vs. 2012E**



Source: Company data, Credit Suisse estimates.

Note: Data reflects month in which rig began/is expected to begin earning revenue.

Exhibit 156: **Monthly Schedule of Newbuild Start-ups**



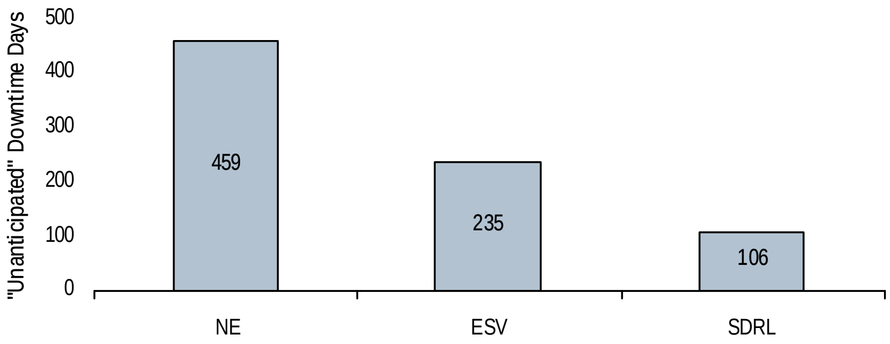
Source: Company data, Credit Suisse estimates.

Note: All newbuilds except RDC's are floating rigs, data reflects month in which rig is expected to begin earning revenue.

3. Unanticipated Downtime

Unanticipated downtime is the hardest to predict, but we have seen a relatively consistent pattern throughout 2011 with drillers such as ATW and DO among the more reliable players and others such as RIG, NE and to a lesser extent ESV and SDRL having some issue. We cannot help but believe the past to be at least somewhat of an indicator of the future with regards to performance expectations.

Exhibit 157: **Select Contract Driller "Unanticipated" Floating Rig Downtime, 2011**



Source: Company data, Credit Suisse estimates

Note: Given challenges in parsing out unanticipated versus other downtime for RIG, we have excluded it from this chart, though we note the fall in company revenue efficiency indicates meaningful downtime

We bring subjectivity to our own assessment of earnings risk.

Most below consensus for RIG, NE, and DO

Bringing us back to Exhibit 150, we must establish where we think meaningful risk of any such delays occurring is more or less relevant. We attribute much of our below-consensus estimates for RIG and NE to applying additional downtime vis-à-vis company indications to date. See Exhibit 158.

We summarize key thoughts on select drillers below.

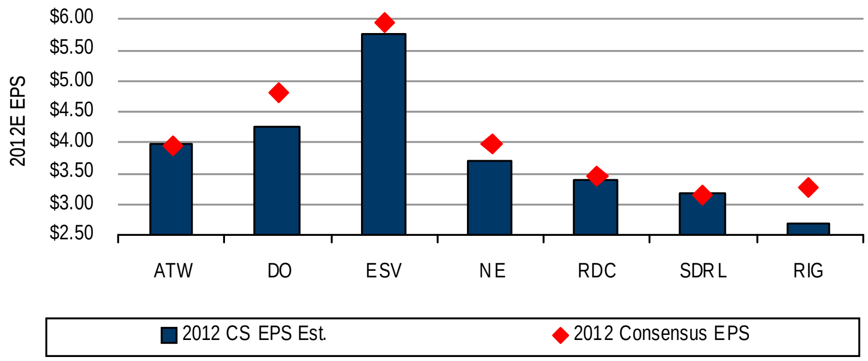
- **RIG:** In our view, RIG's heavy maintenance program planned for 2012 and no clear signs yet that the company has a firm grip on its operations is a cause for additional concern. And we note that even though we model in a lower 91.5% revenue efficiency for contracted floaters in 2012, this is still at the high end of the average range for all RIG floaters in 2011.

- **NE:** Although NE is not among the most impacted in our sensitivity analysis, we note the relatively greater risk of downtime causing scenarios here actually playing out. The company has been plagued with numerous unanticipated downtime days and particularly cites the complexity of the equipment and redundant systems on newer rigs as a cause.
- When reviewing the newbuild risk, despite NE and ESV having 3 rigs each, 2 factors are cause for greater concern for NE than ESV. The first issue is the fact that NE's newbuilds are of a more conventional design in the Globetrotter and Bully designs, which leaves the door open for there to be kinks to iron out after these rigs begin operations.
- We also note the Brazilian customs clearance process is arduous and often causes delays, creating risk that the Bully II rig is delayed.
- **DO:** Although nearly half of DO's floating rig fleet is due to go in the yard in 2012, the company's stellar operational track record leads us to believe the company will be better at managing its time in the yard than we would expect for somebody like RIG. Further we believe that DO's operational excellence in 2011 has not been just luck or solid rig maintenance but that ironically the older equipment, with its simpler (and arguably 'less safe') systems, is less likely to be hit with unplanned downtime.
- **ESV:** Two of ESV's newbuilds are the final installments of the 7-rig 8500 series, of which ESV first started up operations back in 2009 and on which kinks appear to have been largely worked out. And we think the extra time in the yard on the DS-6 to add additional equipment should serve as time to take preventative measures that ensure issues seen on the DS-4 and DS-5 in 2H11 do not repeat on this rig.
- **ATW:** Given the smaller size of its fleet relative to peers, any sort of additional downtime can quickly hit ATW's bottom line, and hence the fact that in our sensitivity analysis ATW screens as the third most vulnerable. Realistically, however, ATW has had a stellar track record on it first ultra-deepwater newbuild (94% uptime) in 2H11 and management is among the most vocal regarding its focus on execution. Similarly, management has proactively indicated that it is getting all the pieces together in order to ensure a smooth yard-stay on the Falcon semi and so we would be of the view that any sort of significant delay on this rig would come as a surprise.

Our Estimates vs. Consensus

While a variety of factors go into estimates, we note the delta between our estimates and consensus going into the new year for 2012 and believe that our more cautious approach towards operational expectations likely account for at least some of the difference.

Exhibit 158: 2012E EPS: Credit Suisse vs. Consensus



Source: Company data, Credit Suisse estimates.

Exhibit 159: Detailed Rig List and EPS Impact Scenarios (NB = Newbuild)

Co.	Rig Name/Category	Rig Type	Downtime Risk Type	Guided Downtime	Dayrate ($)	12 EPS Impact 1 month		Comment					
ATW*	Atwood Condor *(NB)*	Semi	Start-up	n/a	360,000	($0.14)	-4%	Rig on time, ATW has good newbuild start-up record					
	Atwood Falcon	Semi	Planned yard-stay	95 days	385,000	($0.15)	-4%	ATW vocal about its proactive approach to this job					
DO	Ocean Whittington	Semi	Planned yard-stay	120 days	*225,000*	($0.04)	-1%	Uncertain prospects for future work, DO good executors					
ESV	DS-1	Ship	Planned yard-stay	90 days	352,500	($0.04)	-1%	ESV generally good executors					
	DS-5**	Ship	>2 mo's downtime in '11	n/a	471,975	($0.05)	-1%	Addressing kinks on newer DS series, likely improves in '12					
	Ensco 5002	Semi	Planned yard-stay	60 days	200,000	($0.02)	NM	ESV generally good executors					
	DS-6 *(NB)*	Ship	Start-up	n/a	*480,000*	($0.06)	-1%	Add'l yard-time likely means smoother start-up vs. sister rigs					
	Ensco 8505 *(NB)*	Semi	Start-up	n/a	475,000	($0.05)	-1%	Recent 8500 series has good start-up track record					
	Ensco 8506 *(NB)*	Semi	Start-up	n/a	*425,000*	($0.05)	-1%	Recent 8500 series has good start-up track record					
HERO	6 GoM surveys	Jackup	Planned yard-stay	45 days/6 rigs	60,000 (avg.)	($0.06)	n/a						
	Hercules 185	Jackup	Planned yard-stay	90 days	60,000	($0.01)	n/a	R&M work that has already been modestly extended					
	Hercules 208	Jackup	Planned yard-stay	45 days	*90,000*	($0.01)	n/a						
	Hercules 261	Jackup	Planned yard-stay	60 days	84,000	($0.01)	n/a						
	Hercules 262	Jackup	Planned yard-stay	90 days	80,000	($0.01)	n/a						
NE	Dave Beard**	Semi	>2 mo's downtime in '11	n/a	236,500	($0.02)	-1%	Rig had greater than average downtime in 2011					
	Roger Eason**	Ship	>2 mo's downtime in '11	n/a	373,025	($0.04)	-1%	Rig had greater than average downtime in 2011					
	Paul Wolff**	Semi	>2 mo's downtime in '11	n/a	460,100	($0.05)	-1%	Rig had greater than average downtime in 2011					
	Bully I *(50% interest), NB*	Ship	Start-up	n/a	442,500	($0.03)	-1%	New design, chance for start-up issues greater					
	Bully II *(50% interest), NB*	Ship	Start-up	n/a	442,500	($0.03)	-1%	New design, chance for start-up issues greater					
	Globetrotter I (NB)	Ship	Start-up	n/a	440,750	($0.04)	-1%	New design, chance for start-up issues greater					
RDC	3 Tarzan Class Upgrades	Jackup	Planned yard-stay	60 days/ 3 rigs	127,500	($0.08)	-3%	Saudi upgrade work on other RDC, peer rigs has had delays					
SDRL	West Hercules	Semi	Planned yard-stay	105 days	500,000	($0.03)	-1%	SDRL generally good executors					
	West Capricorn (NB)	Semi	Start-up	n/a	487,000	($0.03)	-1%	SDRL has had good start-up track record					
	West Leo (NB)	Semi	Start-up	n/a	525,000	($0.03)	-1%	SDRL has had good start-up track record					
RIG	Ultra-deepwater	Floaters	Planned yard-stay	257 days	507,000 (avg.)	($0.20)	-8%	87% revenue efficiency in 2011 through 3Q					
	Deepwater	Floaters	Planned yard-stay	544 days	386,000 (avg.)	($0.16)	-6%	90% revenue efficiency in 2011 through 3Q					
	Midwater	Floaters	Planned yard-stay	612 days	264,000 (avg.)	($0.15)	-6%	92% revenue efficiency in 2011 through 3Q					
	RIG Revenue Efficiency Scenario					**92.5% Rev Eff**		**90% Rev Eff.**		**87.5% Rev Eff.**		**85% Rev Eff.**	
	Ultra-deepwater	Floaters	n/a	n/a	n/a	$0.08	3%	$0.14	-5%	($0.36)	-13%	($0.57)	-21%
	Deepwater	Floaters	n/a	n/a	n/a	$0.02	NM	($0.01)	NM	($0.03)	-1%	($0.04)	-2%
	Midwater	Floaters	n/a	n/a	n/a	$0.01	NM	($0.06)	-2%	($0.10)	-4%	($0.15)	-5%

** Note: ATW represents fiscal year (September '12 end)*

***Note: Rig had >2 months of downtime in 2011 hence inclusion in analysis*

General Note 1: Italicized dayrate represents a dayrate estimate

General Note 2: Dayrates assume 50% of bonus potential

Source: Company data, Credit Suisse estimates.

Canadian E&P in 2012—Accelerating Asian Interest

Gas JVs Strengthen the East West Connection

As illustrated in Exhibit 1 below, Asian investment in Canada's oil and gas sector has accelerated over the past three years through a combination of joint ventures, asset purchases, and opportunistic M&A. While individual deal size has remained relatively small (i.e., below the C$5 billion threshold), taken together, recent Asia-Canada transactions now add up to over C$20 billion. Investment by Asian entities into Canada has also broadened to include the likes of PTTEP and PETRONAS, and increasing emphasis is being placed on shale gas joint ventures with a view to future LNG exports off the West Coast. We believe the East-West connection between Asia and Canada is set to expand further, as both markets seek to diversify their resource exposure.

Asian investment in Canada's oil and gas sector has accelerated

Exhibit 160: Asian-Canada Investment (2005-present)

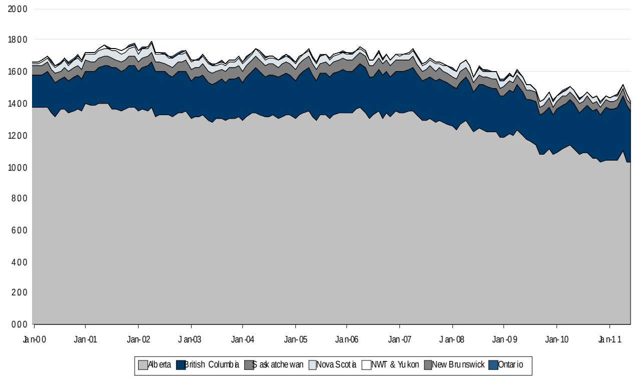
Type	Date	Seller	Buyer	Value (C$ billions)	Carry %	Property	Interest	Notes
Joint Venture	Nov-11	NXY	Inpex	0.70	50%	Horn River, Cordova & Liard (shale gas)	40%	Carrying 75% of NXY capex in 2012
M&A	Oct-11	DAY	Sinopec	2.85	N/A	Deep Basin/Cardium (oil & gas)	N/A	
M&A	Jul-11	OPC	CNOOC	2.10	N/A	Long Lake Project (oil sands)	35%	
Joint Venture	Jun-11	PRQ	PETRONAS	1.07	75%	North Montney (tight gas)	50%	Carry = 75% of PRQ capex
Farm Down	Nov-10	STO	PTTEP	2.28	N/A	Kai Kos Dehseh Project (oil sands)	40%	
Joint Venture	Aug-10	PWT	Mitsubishi	0.85	71%	Cordova (shale gas)	50%	Carry = 50% of PWT capex
Joint Venture	May-10	PWT	CIC	0.82	62%	Peace River (oil sands)	45%	Carry = 91% of PWT capex & opex
Asset Purchase	Apr-10	COP	Sinopec	4.65	N/A	Syncrude (oil sands)	9%	
Joint Venture	Feb-10	ECA	KOGAS	0.57	100%	Montney + Horn River (tight/shale gas)	50%	Carry = 100% of ECA capex
M&A	Oct-09	HTE	KNOC	4.10	N/A	W. Canada (upstream) E. Coast (refining)	N/A	
Farm Down	Aug-09	ATH	PetroChina	1.90	N/A	Mackay River/Dover (oil sands)	60%	
Asset Purchase	Jul-06	NEM	KNOC	0.27	N/A	BlackGold (oil sands)	100%	
Farm Down	May-05	SYN	Sinopec	0.11	N/A	Northern Lights (oil sands)	40%	
Equity Position	Apr-05	MEG	CNOOC	0.15	N/A	Christina Lake (oil sands)	17%	
Total				22.41				

Source: Company data, Credit Suisse estimates.

With Western Canada gas prices averaging below C$4/mcf and with WTI having disconnected from Brent, Canada's need to diversify export markets within and beyond the US has become more evident to the Canadian producer and government. Low Western Canada gas prices in particular have collided with the discovery and development of large-scale unconventional gas resource in Northeast B.C. over the past few years and the specter of an increasingly self-reliant US market. Against this backdrop, and with structural change in North American gas demand seemingly years away and dependent on displacement of coal in power markets, Canadian producers sitting on large gas resource potential are now participating in joint venture transactions at an increasing rate and are seeking partners that can offer LNG markets exposure longer term.

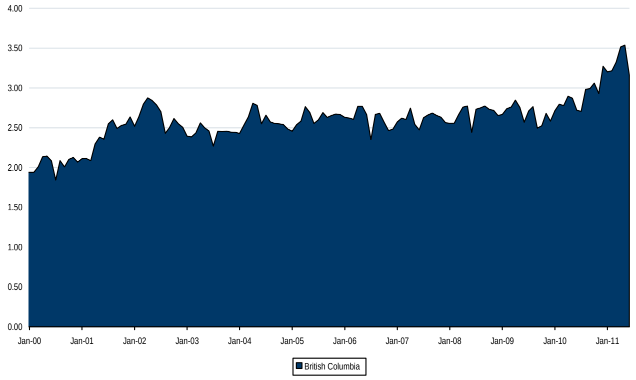
The need to diversify export markets is coming into greater focus with recent JVs

Exhibit 161: Canadian Gas Production (Bcf/d)



Source: NEB.

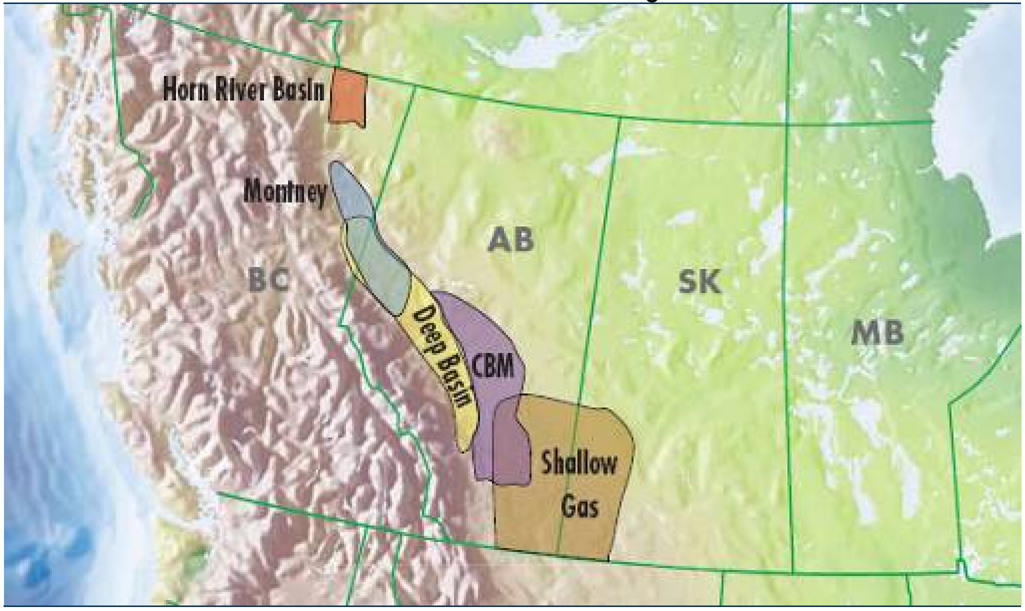
Exhibit 162: B.C. Gas Production (Bcf/d)



Source: NEB.

For producers, recent joint venture transactions have surfaced some immediate value for otherwise "stranded" resource (e.g., +/- C$0.20/mcf of contingent resource), while allowing for higher-risk delineation and appraisal work to proceed at reduced cost. Recent joint venture transactions with Asian partners (e.g., NXY-Inpex, PRQ-PETRONAS, PWT-Mitsubishi) have included upfront cash proceeds ranging from 50% to 75% of the total transaction value and a substantial carry of the producers already incurred and/or future capex. For Asian partners, participation in Canadian gas projects follows a general global pattern toward increased participation in the LNG value chain to include upstream and liquefaction, and in the long term could offer a means to diversify supply sources away from LNG heavyweights Qatar and Australia.

Exhibit 163: Western Canada Natural Gas Production Regions



Source: Company data, Credit Suisse estimates.

To date, Horn River shale and Montney tight gas resource have formed the basis for gas JVs

Liard Basin and Duvernay Shale emerging into the picture

To date, Horn River Basin shale (including the Cordova shale to the east) and Montney tight gas resource has formed the primary basis for gas joint ventures, including Asia-Canada transactions. Looking forward, the Duvernay shale within the Alberta Deep Basin and shale gas from the Liard basin that spans the B.C./Northwest Territories border could also participate. Indeed, the recent Nexen/Inpex transaction includes both existing production and 4-15 Tcf of contingent resource from Horn River Basin properties but also a further 5-23 Tcf of prospective resource from the Liard Basin. While more speculative, the recently announced purchase of Daylight Energy by Sinopec may have been motivated in part by Daylight's meaningful acreage position within the Duvernay shale.

Exhibit 164: **Nexen—Shale Gas Position (Tcf)**

	Reserves		Contingent Resources			Prospective Resources		
	Proved	2P	Low	Best	High	Low	Best	High
Horn River (Dilly Creek)	0	0	3	5	10	0	0	0
Cordova	0	0	1	3	5	0	0	0
Liard	0	0	0	0	0	5	13	23
Total Shale Gas	0	0	4	8	15	5	13	23

Source: Company data.

Encana attracting third party capital as part of its corporate strategy

So what's next? With the caveat that it is always difficult to predict how the transaction landscape will evolve, we expect Encana will continue to attract third party investment as part of its corporate strategy and given the company's large base of well-defined economic contingent resources.

Up next? Possibly Encana's Cutbank Ridge lands

Following exclusive negotiations with PetroChina that did not result in a joint venture transaction concerning Encana's Cutbank Ridge (includes Montney lands) business assets, the company has reinitiated the process to find a joint venture partner for an interest in ~420,000 undeveloped acres in the region. A Cutbank Ridge transaction could potentially be worth up to C$3.0 billion (assumes PRQ-PETRONAS JV transaction metric of ~C$14,275/acre), including a possible upfront cash payment of ~C$750 million. Encana has already formed a joint venture with KOGAS on parts of its Cutbank Ridge and Horn River lands whereby KOGAS is investing approximately C$565 million over a three-year period to earn a 50% interest in 154,000 net acres (25,000 net acres in the Horn River Basin and 129,000 net acres in the Montney play). The ECA/KOGAS joint venture was more recently upsized by another C$185 million on a similar basis to cover an additional 20,000 net acres in the Horn River Basin.

Exhibit 165: **Possible Canadian LNG Export Projects (Bcf/d)**

Status	Operator	Partners	Location	Capacity	Trains	Potential Startup
Pre-Construction Phase	Apache	EOG/Encana	Kitimat	1.4	2	2015
Initial Investment Phase	Shell	KOGAS/CNPC/Mitsubishi	Kitimat	N/A	N/A	N/A
Feasibility Phase	PETRONAS	Progress	N/A	1.0	2	2018+
Investigation Phase	N/A	NXY/Inpex	N/A	N/A	N/A	N/A

Source: Company data.

Other potential transactions both near and longer term

Ultimately we see the possibility of more East-West connections across the sector involving a range of assets and companies. While the following may or may not include an Asian partner, companies currently considering a strategic transaction of some sort include Cenovus (Borealis Region—oil sands), Connacher (Great Divide—oil sands), Husky (Ansell—tight liquids-rich gas). Other assets that could find their way into a strategic transaction over the longer term, potentially involving an Asian partner, might include ARC Resources' Attachie property in the Montney play and Lone Pine's Liard shale position in the Northwest Territories

MLPs in 2012, Another Strong Year

CS Take on Natural Gas Liquids (NGLs): Another Year of Strength in 2012

MLP investment climate remains supportive

NGL market to remain tight throughout 2012: In our view, the NGL market will remain tight throughout 2012. We expect modest NGL supply growth in 2012 supported by strong producer economics in the liquids-rich plays. Demand should also keep pace with increasing supplies as crackers continue to find ways to increase ethane cracking capabilities and exports continue to ramp. As a result, inventories should remain relatively low throughout 2012, in our view. Furthermore, we expect Mont Belvieu ethane to continue to trade at an elevated premium due to limited takeaway capacity to the Gulf Coast.

2013 is the date to circle: Fears of an impending wave of ethane to the Gulf Coast are understandable. However, we believe this is more of a 2013 concern. At the present time, ethane transportation capacity remains constrained as evidenced by the wide Conway to Mont Belvieu spread. This transportation bottleneck will not be resolved until 2013 when a slew of new NGL pipelines are scheduled to come on-line. Do note, we are not calling for an oversupply of ethane in 2013. However, the market may loosen from its currently tight conditions.

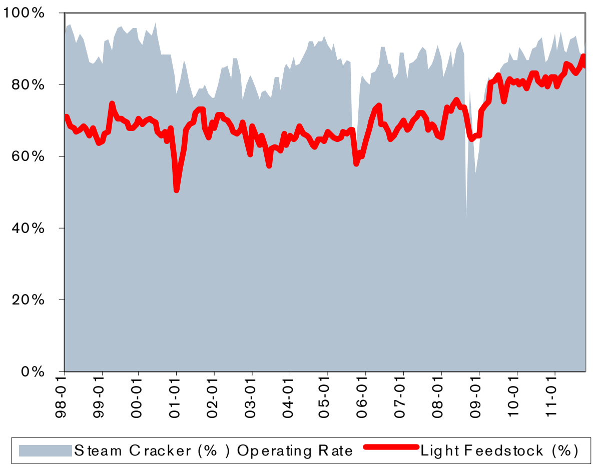
Long-term supply/demand outlook remains constructive: We believe the NGL market will remain balanced over the long term. The development of the US shales continues to provide the US based petrochemical industry with a low-cost, globally advantaged feedstock, whose use will be maximized by the industry, in our view. Specifically, we expect additional world-scale, ethane cracking facilities to be constructed in the US over the next 5 years.

Investment Cclimate for MLPs' remains supportive: The investment climate for MLPs remains supportive, in our view. Infrastructure remains short in several of the key growth basins (Bakken, Niobrara, Marcellus) and new plays continue to develop providing the MLPs with new investment horizons (Utica, Uinta). Gathering, processing, fractionation and logistics assets are likely to continue to perform well as drilling in the liquids-rich plays remains supported by economic returns. Furthermore, processing economics should remain healthy as we expect similar oil, NGL and gas prices in 2012. Finally, we do expect project competition to heat up in 2012. Growth basins and services are likely to draw additional competition, thus lowering project returns (albeit at still healthy levels).

NGL Market to Remain Tight throughout 2012

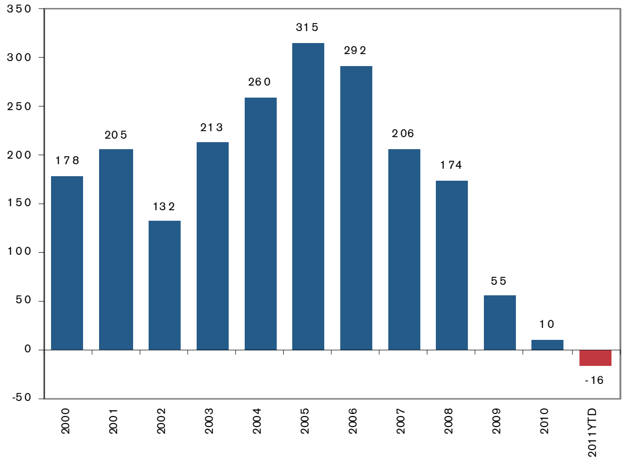
In our view, the NGL market will remain tight throughout 2012. We expect modest NGL supply growth in 2012 supported by strong producer economics in the liquids-rich plays. Demand should keep pace with increasing supplies as petrochemicals continue to find ways to increase light feedstock (ethane, propane and butane) cracking capabilities and exports continue to ramp (propane and butane for now…ethane to come). Since 2009, US steam crackers increased light feedstock utilization from 66% to 85% of the feedslate as of November 2011. This trend should continue as the industry converts and debottlenecks light feedstock cracking capacity owing to the superior margins provided by these NGLs (specifically ethane). Another underlying structural shift in demand is the export of NGLs. As domestic NGL production has grown, imports have declined and supplies have been bid away by the export market owing to their global competitiveness.

Exhibit 166: Steam Cracker Operating Rate (%) vs. Light Feedstock Usage (%) (1998-2011)



Source: Hodson, Credit Suisse estimates.

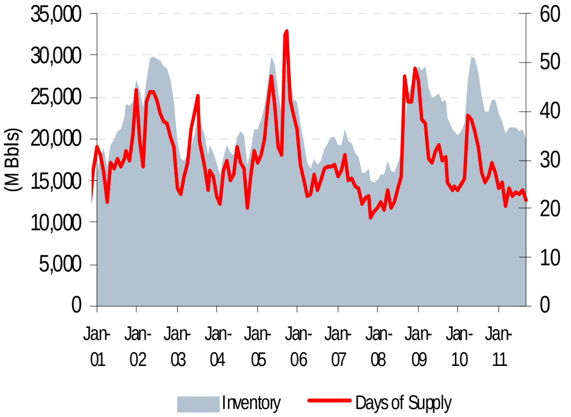
Exhibit 167: US Net Imports / (Exports) of Natural Gas Liquids (NGLs) (2000-2011YTD) (m bbls/d)



Source: Company data, Credit Suisse estimates.

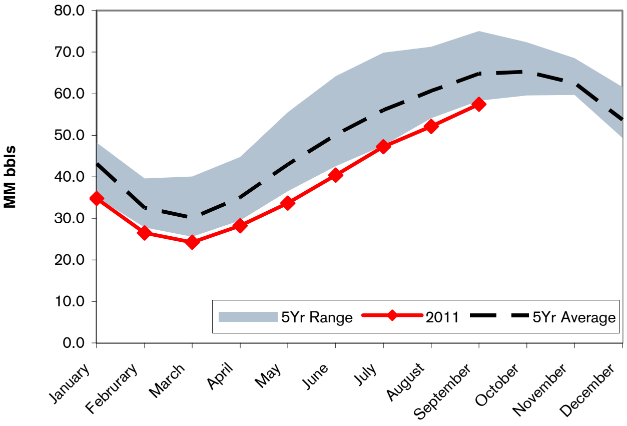
Currently, NGL inventories remain low relative to historical levels (Exhibit 168and Exhibit 169) despite a robust 5.1% year-to-date increase in total supply. With supply growth expected to moderate and ethane demand to continue to outstrip supply, inventories should remain relatively low throughout 2012, in our view.

Exhibit 168: Ethane Inventories and Days of Supply



Source: Company data, Credit Suisse estimates.

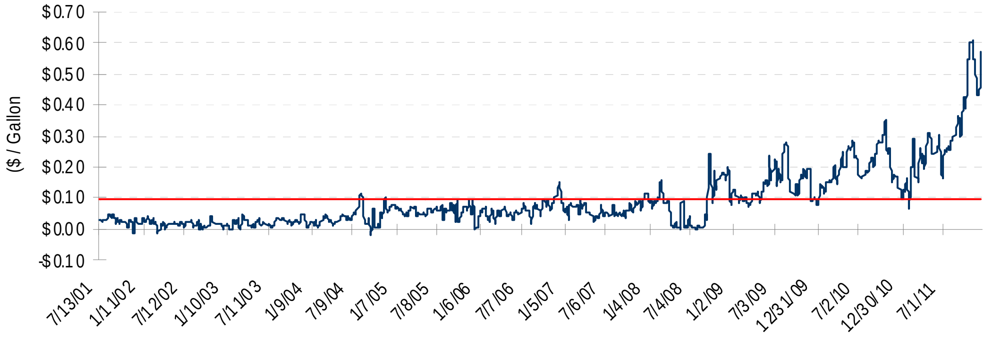
Exhibit 169: Propane Inventories vs. 5-Year Range



Source: Company data, Credit Suisse estimates.

Furthermore, we expect Mont Belvieu ethane to continue to trade at an elevated premium owing to limited takeaway capacity to the Gulf Coast. During 2012, additional NGL supplies should funnel to Conway. However, with NGL pipelines not scheduled to come on-line until 2013, the Conway bottleneck will persist throughout 2012, in our view.

Exhibit 170: Mont Belvieu to Conway Ethane Spread ($/gal) (2001–2011)



Source: Company data, Credit Suisse estimates.

2013 Is the Date to Circle

Fears of an impending wave of ethane to the Gulf Coast are understandable. However, we believe this is more of a 2013 concern. At the present time, ethane transportation capacity remains constrained as evidenced by the wide Conway to Mont Belvieu spread (Exhibit 170). This transportation bottleneck will not be resolved until 2013 when a slew of new NGL pipelines are scheduled to come online (Exhibit 171).

Exhibit 171: Proposed NGL Pipelines from Conway & West/South Texas to the Gulf Coast

Conway to Mt. Belvieu - NGLs			
Project	Capacity	Sponsors	Expected Timing
Texas Express Pipeline	280,000 bpd	Enterprise / Enbridge	2Q13
Southern Hills	150,000 bpd	DCP Midstream	mid-2013
Sterling III	193,000 bpd	ONEOK	late-2013
Total	**623,000 bpd**		
West/South Texas to the Gulf Coast - NGLs			
Project	Capacity	Sponsors	Expected Timing
Sandhills	200,000 bpd	DCP Midstream	2013
Lone Star	130,000 bpd	Energy Transfer / Regency	2013
Enterprise Eagle Ford Pipeline	100,000 bpd	Enterprise	2013
Total	**430,000 bpd**		

Source: Company data, Credit Suisse estimates.

A total of over 1,000m bpd of NGL transportation capacity is scheduled to begin operations over the course of 2013. Assuming all pipelines are built and ethane comprises 50% of the NGL barrels, these pipelines alone have the capacity to transport over 500m bpd of ethane to the Gulf Coast. Factoring in Enterprise's (EPD) Marcellus ethane pipeline with 125m bpd of capacity scheduled to begin operations in 2014, the total pipeline capacity additions have the potential to increase Gulf Coast ethane supplies by ~625m bpd, a 69% increase over current ethane supplies of 905m bpd.

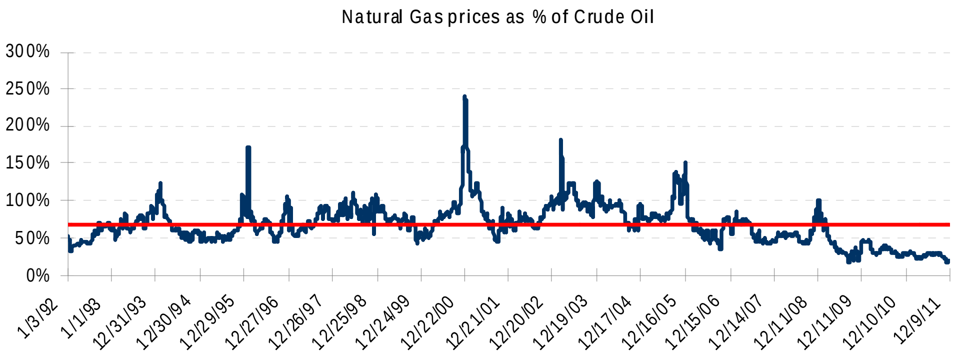
Currently ethane in areas such as the Bakken, Permian, Eagle Ford, Mid Continent and Marcellus is being blended in the gas stream to varying degrees. As these NGL pipelines begin operations, we suspect that a portion of this ethane will find its way into these pipelines in an attempt to realize better pricing.

Do note, our intent is to simply flag the potential supply increase, and we would expect volumes on these pipelines to ramp over time. We are not calling for an oversupply of ethane in 2013, however the market may loosen from its currently tight conditions. The key data point to monitor will be the pace of ethane cracking debottlenecking, expansions and new builds. The potential for a timing mismatch between supply and demand exists. However, we believe any mismatch will be resolved in due time given the attractive ethane cracking economics. This is reinforced by the petrochemical's stated desire to increase ethane cracking capabilities.

Long-Term NGL Outlook Remains Constructive

We believe the NGL market will remain balanced over the long-term. The development of the US shales and resulting low natural gas to crude oil ratio (Exhibit 172) continues to provide the US based petrochemical industry with a low-cost, globally advantaged feedstock, whose use will be maximized by the industry, in our view. Specifically, we expect additional world-scale, ethane cracking facilities to be constructed in the US over the next 5 years. In our view, the biggest risk to the NGL story remains another recession, which is outside the scope of this analysis.

Exhibit 172: **Natural Gas Prices (Henry Hub) as a % of Crude Oil Prices (WTI)**



Source: Facset, Credit Suisse estimates.

Exhibit 173: **Announced Potential Steam Cracker Capacity Expansions**

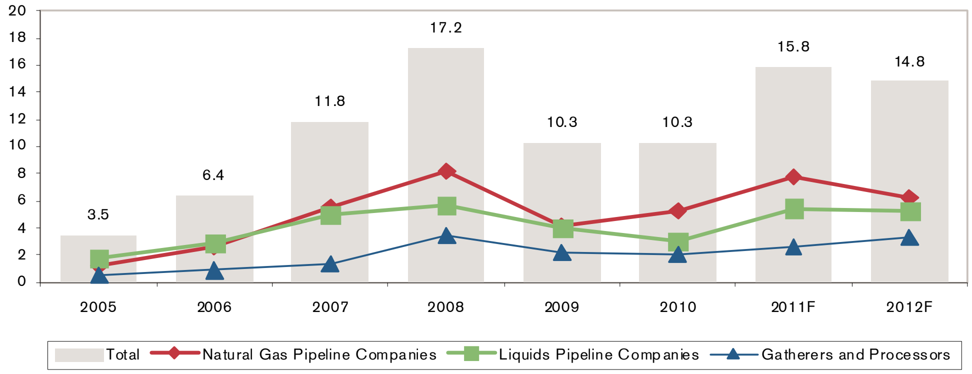
Steam Cracker Capacity Expansions			
Project	Capacity (mm lb/yr)	Sponsors	Expected Timing
Lake Charles 2 expansion	240	Westlake	2012
Geismar ethane cracking capacity expansion	600	Williams	2013
Lake Charles 1 expansion	NA	Westlake	2014
World-scale ethane cracker	2,200	Chevron Phillips	2014/2015
Increasing capacity at Point Comfort	1,000	Formosa	2015
Debottlenecking additional capacity	250	Ineos	NA
Debottlenecking additional capacity	NA	ExxonMobil	NA
Debottlenecking additional capacity	NA	Lyondell	NA
World-scale ethylene plant	NA	Dow	2017
Total Expansion	**4,290+**		
Current Name Plate Capacity	57,747		
Potential Capacity Expansion	**7.4%+**		

Source: Hodson, Credit Suisse estimates.

Investment Climate for MLPs Remains Bright

The investment climate for MLPs remains bright, in our view. Infrastructure remains short in several of the key growth basins (Bakken, Niobrara, Marcellus) and new plays continue to develop providing the MLPs with new investment horizons (Utica, Uinta). Gathering, processing, fractionation and logistics assets are likely to continue to perform well as drilling in the liquids-rich plays remains supported by economic returns. Furthermore, we expect processing economics to remain healthy as we expect similar oil, NGL and gas prices in 2012. Finally, we do expect project competition to heat up in 2012. Growth basins and services are likely to draw competition, thus lowering project returns (albeit at still healthy levels).

Exhibit 174: MLP Capex (2005-2012F), $bn



Source: Company data, Credit Suisse estimates, FactSet.

Exhibit 175: MLP Exposure to Shales by Segment

Play	**Gatering & Processing & Logistics**
Bakken	OKS / TLLP
Eagle Ford	CHKM / CPNO / EPD / ETP / KMP / MWE / RGP
Fayetteville	CMLP
Haynesville	CHKM / CPNO / DPM / EPD / EROC / ETP / MMLP / MWE / OKS / RGP / WPZ
Marcellus	BWP / MWE / WPZ
MidCon	APL / CHKM / CMLP / CPNO / EEP / EPD / EROC / ETP / MWE / NGLS / OKS / RGP
Permian	APL / CHKM / CMLP / EPD / NGLS / RGP / WES
Rockies	EPD / ETP / KMP / OKS / WES / WPZ
Play	**Pipeline & Storage**
Bakken	EEP / KMP / OKS / PAA / TCLP
Eagle Ford	BWP / CPNO / DPM / EPD / ETP / KMP / NS / WPZ
Fayetteville	BWP / EPD / ETP / KMP / SEP / XTEX
Haynesville	BKEP / BWP / EEP / EPD / EROC / ETP / KMP / PAA / RGP / SEP / TCLP / TLP / WPZ / XTEX
Marcellus	BPL / EPD / MWE / NRGY / SXL / WPZ
MidCon	APL / BKEP / BPL / CMLP / EEP / EPB / EPD / EROC / ETP / HEP / KMP / MMP / OKS / PAA / TCLP / WPZ / XTEX
Permian	BPL / EPD / ETP / HEP / KMP / MMP / OKS / PAA / SXL
Rockies	DPM / EEP / EPB / EPD / HEP / KMP / OKS / PAA / WES / WPZ

Source: Company data, Credit Suisse estimates.

Canadian Infrastructure in 2012

For Canadian energy infrastructure, we only wish to focus on three themes:

- Comparing Canadian crude;
- Pipelines aplenty; and
- Powerful Alberta.

Each of these areas is addressed in detail below.

It clearly makes sense to promote imports of Canadian crude given the alternatives; multiple pipeline solutions will inevitably emerge

Comparing Canadian Crude

Given the US government's action toward TransCanada's Keystone XL pipeline, we view it necessary to revisit a unique comparative of Canadian crudes versus other areas around the world. Exhibit 176lists the sources of US crude oil imports and a summary score from a variety of metrics for those countries. In both cases, Canada ranks as the largest exporter of crude and as the most favorably ranked nation.

Exhibit 176: Top Ten Oil Exporting Countries to the US Imports in 2010

Thousands of barrels a day

Country	Crude Import ('000/day)	% of Imports	Composite Rank
Canada	1,970	21.4%	7.3
Mexico	1,152	12.5%	58.9
Saudi Arabia	1,082	11.7%	55.9
Nigeria	983	10.7%	120.3
Venezuela	912	9.9%	122.3
Iraq	415	4.5%	120.0
Angola	383	4.2%	140.1
Colombia	338	3.7%	66.6
Algeria	328	3.6%	108.2
Russia	269	2.9%	104.0

Source: US Energy Information Administration and Credit Suisse.

There is some variance in these countries toward the bottom of the list, however, a level of consistency exists with the top five ranks. Clearly, the US is substantially reliant upon a selection of foreign crude oil producing countries. From our perspective, this collection of countries is different across a variety of metrics.

In our view, many of these metrics implicitly address some of the politics, reliability and the potential sustainability of crude oil. Quite simply, Canadian sourced crude oil is positioned extremely positively against the other major nations exporting crude oil to the US on many metrics. The individual metrics are addressed in greater detail below, however, we created a composite to rank the top 10 oil exporting countries. Exhibit 177 contains our composite scores for those countries.

Exhibit 177: **Composite Table (Methodology Is Below)**

		Rankings					
Country	Adjusted Rank	Index of Economic Freedom	Ease of Doing Business	Corruption Perceptin Index	Human Development Index	State of World Liberty	Rule of Law Index
Canada	7.3	6	13	6	6	3	11
Mexico	58.9	48	53	98	57	52	47
Saudi Arabia	55.9	54	12	50	56	122	N/A
Nigeria	120.3	111	133	134	156	113	51
Venezuela	122.3	175	177	164	73	118	60
Iraq	120.0	N/A	164	175	132	N/A	N/A
Angola	140.1	161	172	168	148	145	N/A
Colombia	66.6	45	42	78	87	98	36
Algeria	108.2	132	148	105	96	135	N/A
Russia	104.0	143	120	154	66	124	43
Ranked countries		179	183	178	187	159	66

Source: United Nations Development Programme, Transparency International, The Heritage Foundation, The World Bank Group, The State of World Liberty Project, The World Justice Project and Credit Suisse.

Our methodology for the composite was simple and based upon the following weights:

- Given the comprehensiveness of the Human Development Index, we assigned a 25% weighting to this component; and,
- Equal weights of 15% to each of the corruption index, ease of doing business, index of economic freedom, state of world liberty project and the rule of law index.

In the few cases that data was not available for a specific country, we used the average rank from our sample to aid our composite calculation.

These metrics were discussed in detail in our note entitled "*Comparing Canadian crude*" published on 14 November 2011.

Pipelines Aplenty

We continue to believe Canadian crude and, more broadly, hydrocarbons will continue as a major supplier to the US. The case for Canadian crudes across a multitude of metrics is stronger than most competitive crudes from other nations. From our perspective, these factors support our opinion that Keystone XL will be eventually approved. Some potential investment themes include:

- **More pipelines:** By the end of this decade, we continue to believe a broader and more robust pipeline network will exist across North America. In our view, that network will be necessary for the ongoing development of the upstream industry ranging from continued oil sands project development to growing volumes of crude and other hydrocarbons from a variety of basins across the continent.
- **Timing may create dislocations of value:** Clearly, timing can be an issue with large scale capital projects that have a lasting and meaningful impact. Yet, over a period of time, delays and deferrals of several quarters or years are not overly meaningful in the context of asset life for pipeline companies. Delays, however, may meaningfully affect the economics of regional refiners in selected geographies.
- **Multiple solutions necessary:** Ultimately, we believe a variety of solutions will be required for the benefit of the industry, including: selected Enbridge reversals (Line 9 and Seaway); Keystone XL (TRP); Gateway (ENB); and, TMX Expansion (KMI/KMP).
- **A twinning solution:** We believe the delay in Keystone XL's approval is not really a rejection. In our view, a reasonable number of political accommodations may be made to see the project eventually succeed. Yet, there is a possible case for TransCanada

to effectively twin the existing base Keystone project as an expansion project. In our view, such a project would face less difficulty than XL experienced on a stand-alone basis. Negatively, we anticipate this type of project to have inferior economics versus the original XL proposal.

- **A matter of balance**: The industry requires a delicate balance of production, pipeline capacity and downstream needs that are inherent with conflicting objectives.
- **NIMBYism in effect**: Building selected types of infrastructure has never been easy and well organized environmental groups have often outmaneuvered the industry in the battle of public opinion. This factor looks to make future building efforts even more challenging.
- **Location, location, location**: Given the difficulty in building selected infrastructure assets, some existing energy infrastructure may have enhanced value if expansion possibilities exist.
- **Political season:** With a major US election year on the horizon, a potentially major issue of concern for the energy industry is the potential reemergence of a political campaign against a heavier crude slate.

Powerful Alberta

Alberta continues to be our favorite Canadian power market. Exhibit 178 provides a snapshot view of Alberta's average demand and pricing data over the last 12 months.

Exhibit 178: **Monthly AESO Data**

Time Frame	Average Demand (MW)	Weighted Avg. Price ($/MWh)	Demand chg. y/y	Price chg. y/y	Demand chg. m/m	Price chg. m/m
2011 Nov	8,772	113.72	1.4%	125.2%	6.9%	57.7%
2011 Oct	8,202	72.10	1.7%	129.9%	0.1%	-30.4%
2011 Sept	8,195	103.60	4.2%	258.5%	-1.9%	-22.3%
2011 Aug	8,354	133.39	3.9%	234.8%	0.9%	102.0%
2011 Jul	8,276	66.05	3.1%	58.5%	5.1%	-14.3%
2011 Jun	7,873	77.11	-0.1%	30.3%	3.5%	131.5%
2011 May	7,606	33.31	-1.3%	-76.2%	-6.1%	-37.7%
2011 Apr	8,100	53.49	4.3%	5.6%	-7.1%	7.6%
2011 Mar	8,720	49.70	6.9%	37.7%	-1.9%	-61.2%
2011 Feb	8,893	128.07	4.6%	188.8%	-0.5%	54.7%
2011 Jan	8,940	82.76	4.7%	87.6%	-0.9%	35.2%
2010 Dec	9,018	61.22	3.4%	10.7%	4.2%	21.3%
2010 Nov	8,653	50.49	6.6%	-1.9%	7.3%	61.0%
2010 Oct	8,064	31.37	1.2%	-12.0%	2.6%	8.5%

Source: Alberta Electric System Operator (AESO) and Credit Suisse.

The North American Electric Reliability Corporation's "*2011 Long-Term Reliability Assessment*" published on November 2011 ranked Alberta among the highest average annual growth rate for the next 10-years, second only to Mexico.

As a comparison, Ontario's power demand growth has been mixed as can be seen on Exhibit 179.

Exhibit 179: Monthly IESO Data

Time Frame	Average Demand (MW)	Weighted Avg. Price ($/MWh)	Demand chg. y/y	Price chg. y/y	Demand chg. m/m	Price chg. m/m
2011 Nov	15,439	28.76	-1.7%	-11.4%	4.3%	-2.1%
2011 Oct	14,800	29.38	0.7%	-2.7%	-4.4%	-7.8%
2011 Sep	15,479	31.88	0.9%	-7.1%	-8.1%	-7.6%
2011 Aug	16,844	34.51	-3.0%	-26.2%	-5.8%	-6.9%
2011 Jul	17,874	37.08	-0.1%	-31.7%	14.5%	7.3%
2011 Jun	15,608	34.55	-2.8%	-16.9%	7.7%	33.4%
2011 May	14,491	25.89	-5.1%	-35.9%	-3.3%	-12.9%
2011 Apr	14,983	29.71	3.0%	-6.3%	-9.8%	-6.0%
2011 Mar	16,603	31.62	5.7%	9.9%	-5.3%	-6.1%
2011 Feb	17,523	33.68	0.2%	-8.3%	-2.0%	2.1%
2011 Jan	17,879	32.99	1.2%	-13.7%	4.6%	-5.1%
2010 Dec	17,086	34.76	0.4%	-3.4%	8.8%	7.1%
2010 Nov	15,700	32.47	1.7%	17.7%	6.9%	7.6%
2010 Oct	14,690	30.18	-2.3%	-0.5%	-4.3%	-12.0%

Source: Independent Electricity System Operator (IESO) and Credit Suisse.

For a variety of reasons, we prefer Capital Power Corporation over other Alberta-exposed generators at this time.

Shipping in 2012

AHTSs—Evolution or Extinction

The move by big oil to drill for oil and gas farther offshore has many supply boat owners salivating at the potential opportunities. While we agree they have much to be excited about as drilling picks up in deeper water and in more remote locations, we have our own thoughts on who the winners and the losers are. The pickup in permitting and new drilling rigs being delivered should push day rates and utilization levels higher for the offshore supply sector in 2012 and 2013. However, we see a structural problem looming for certain vessel types, specifically Anchor Handling Towing (AHT) vessels and to a lesser extend for Anchor Handling Towing Supply (AHTS) vessels. We estimate that the Anchor Handler capable boats make up roughly 35% of the total offshore supply boat fleet.

Changing Tide. As the flexibility and operating cost savings of drillships are realized (drillships cost more to build than semi-submersibles) over semisubmersibles we expect demand for drillships to outpace that of semi-submersibles. We believe the pendulum has swung towards drillships and with that we expect demand to wane for AHTSs and especially AHTs. However, not all AHTSs are doomed as the supply capabilities of these boats has increased dramatically over the last ten years, evolving many AHTSs into more supply boats than anchor handlers.

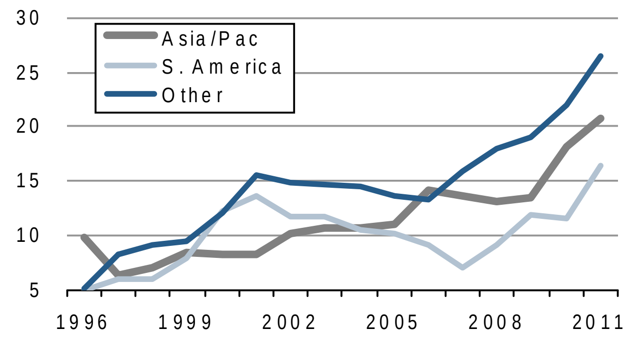
Exhibit 180: AHTS and AHT Specifications over Time

AHTS	Count	Avg BHP	Avg DWT	Avg Cargo Fuel (cu.m)	Avg Drilling Water (cu.m)	Avg Potable Water (cu.m)	Avg Liquid Mud (cu.m)	Avg Deckspace (sq.m.)
2000-2011	1,117	9,500	2,000	1,000	870	410	390	430
1990-1999	120	8,500	1,850	800	850	390	190	380
1980-1989	523	6,350	1,330	750	720	375	180	350
AHT	**Count**	**Avg BHP**	**Avg DWT**	**Avg Cargo Fuel (cu.m)**	**Avg Drilling Water (cu.m)**	**Avg Potable Water (cu.m)**	**Avg Liquid Mud (cu.m)**	**Avg Deckspace (sq.m.)**
2000-2011	265	5,000	870	550	70	200	0	225
1990-1999	81	4,700	550	280	65	145	0	155
1980-1989	66	4,400	400	240	50	130	0	140

Source: Clarksons, Credit Suisse estimates.

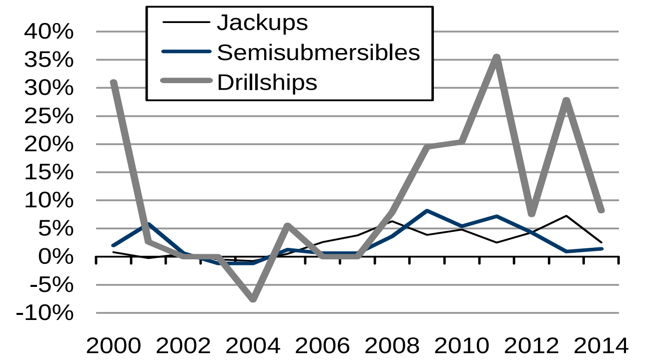
Drillship Growth. The evolution of the offshore market paints a clear picture with drillship fleet growth outpacing the semi-submersible fleet over the last five years with more on the way. The drillship orderbook should extend this trend with 58% growth slated over the next 7 years compared to 15% growth for jackups and 7% for semisubmersibles. In terms of absolute numbers 46 drillships are scheduled for delivery over the next 7 years compared with just 14 semi-submersibles over this period. However, this trend has already been playing out with 42 semi-submersibles (27% growth) delivered over the last 5 years compared with 27 drillships (110% growth) delivered over this same period (Exhibit 180).

Exhibit 181: **Drillship Count by Region**



Source: ODS Petrodata, Credit Suisse estimates.

Exhibit 182: **Rig Growth Rates by Type**



Source: ODS Petrodata, Credit Suisse estimates.

Drillships Still Need Supply Services

Offshore supply boat owners still have much to be excited about as drillships hit the water as drillships still require OSV services. OSVs will still transport drilling supplies, food, fuel; and crew to drillships—they just won't be towing them between locations and placing their anchors. However, on a positive note, the drillships will be working farther offshore and in more remote locations which will require OSVs to travel longer distances, which increase OSV demand.

However, longer term as offshore energy exploration and production moves farther offshore, we expect the preference for drillships over semi-submersibles to reduce demand for AHTSs. This will undoubtedly lead to AHTSs competing for supply work against platform supply vessels (PSVs). The problem with this evolution is that while AHTSs tend to be larger than traditional OSVs their hauling capacity is less. It also becomes an economic problem as well as an AHTS operating as a supply should have trouble earnings a high enough rate to justify the purchase. Large AHTS (15,000+BHP) vessels are currently earning upwards of $45,000/day on average globally while the largest OSVs (4,000+DWT) are only earning $27,000 on average globally.

Exhibit 183: **2011 Towing Versus Supply Comparison**

Specification	AHTS	AHT	OSV
Avg BHP	8,400	5,600	7,500
Avg DWT	2,175	875	4,000
Avg Cargo Fuel (cu.m)	900	500	1,050
Avg Drilling Water (cu.m)	800	75	1,500
Avg Potable Water (cu.m)	400	200	800
Avg Liquid Mud (cu.m)	250	0	500
Avg Deckspace (sq.m.)	450	250	800

Source: Clarksons, Credit Suisse estimates.

So How Many AHTSs Are Doomed?

Considering everything, we examined the AHTS fleet, specifically the vessels with at least 2,000 DWT of hauling capabilities (though on the small side) and a maximum of 15,000 BHP (larger AHTS should still get work towing). We also only focused on vessels built after 1990. We estimate that only 400 vessels (~20% of the fleet) would actually make reasonable OSV candidates, and given the evolution in the OSV market these AHTSs will most likely have difficulty competing in anything less than a bull market. We estimate a vessel overhang of about 200 AHTS vessels as semi submersibles give way to drillships.

Interestingly the orderbook for AHTS and AHTs is rather robust—so not everyone shares our concerns. Currently there are 263 AHTS vessels and 37 AHTs on order for delivery through 2013. While we believe these newer higher spec vessels will find work; we expect these vessels to accelerate the removal of older AHTSs and AHTs from the fleet.

Exhibit 184: Anchor Handling Towing Fleet Profile

		Year Built						
	TOTAL	**2010-2011**	**2005-2009**	**2000-2004**	**1995-1999**	**1990-1994**	**1985-1989**	**1980-1984**
AHTS	1760	317	652	148	80	40	105	418
AHT	413	73	144	48	58	23	18	49
TOTAL	**2173**	**390**	**796**	**196**	**138**	**63**	**123**	**467**
Weight	*100%*	*18%*	*37%*	*9%*	*6%*	*3%*	*6%*	*21%*

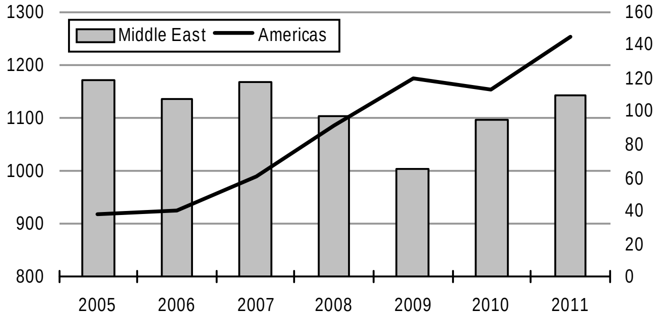
Source: Clarksons, Credit Suisse estimates.

Tanker Traffic—Expect Ton-Mile Expansion in 2012

The tanker industry can be called a lot of things but efficient is not one of them. While ship owners and customers (charterers) for the most part run cost efficient businesses, the actual cargo flows in some cases are anything but. The inefficiencies can stem from refinery limitations to geopolitical issues to energy diversification. These are some of the reasons why a crude tanker will make a 2+ month trip from South America to Asia as opposed to a 2-3 week trip to the US or Europe; or why a super tanker from the Middle East makes a 35 day one-way voyage to the US Gulf as opposed to a 10 day voyage to the Far East. Put another way a VLCC (2 million barrel capacity) can transport 18 million barrels per year from the Middle East to Asia (9 trips per year) versus a VLCC traveling on a loop from the Middle East-Caribbean-Asia-Middle East which can transport 12 million barrels per year (3 loops). The loop method reduces the tanker's annual transportation capacity by about 35% per year but increases the number of tankers demanded globally.

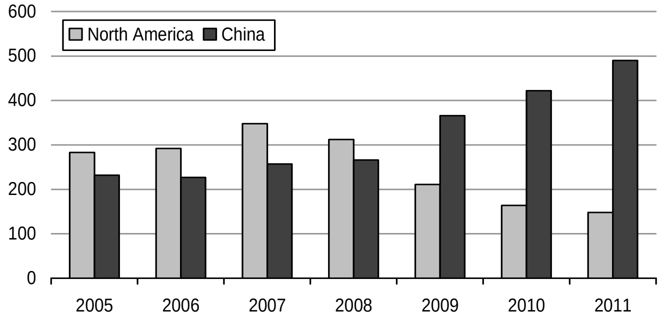
Ton-mile: The distance oil travels on a tanker is referred to as ton-mile demand

Exhibit 185: Middle East and Americas VLCC Spot Loadings



Source: Baltic Exchange, MAREX, Credit Suisse estimates.

Exhibit 186: China & North America VLCC Spot Unloadings



Source: Baltic Exchange, Credit Suisse estimates.

In Exhibit 185 we detail VLCC spot loadings from the Arabian Gulf and the Americas (Caribbean and South America). While The Middle East dominates the VLCC export market (75% share), this has been steady over the last 7 years, the Americas went from a 2% share in 2005 to about 10% of the market in 2011. As Brazil comes online, we expect this number to continue increasing driving ton-miles higher. Turning to demand, China has seen its share of the VLCC market spike from about 15% of all spot fixtures to over 30% this year; we expect China to become ever more important in driving VLCC demand. On the flip side is North America, which has seen its VLCC spot fixture demand cut in half from about 300 fixtures in 2005 to about 150 fixtures this year. Correspondingly, its demand share of VLCC spot fixtures has dropped to about 10% from 20% over this period.

Ton-mile Cheat Sheet

Exhibit 187: Tanker Demand Sensitivity

Incremental Oil Demand (bpd)	100,000	200,000	300,000	400,000	500,000	600,000	700,000
CHINA							
VLCC Demand (AG)	3	5	8	11	13	16	19
VLCC Demand (WAFA)	4	8	12	16	21	25	29
VLCC Demand (Carib/Brazil)	5	10	15	20	25	30	35
INDIA							
VLCC Demand (AG)	1	2	2	3	4	5	5
VLCC Demand (WAFA)	2	4	6	8	10	12	14
VLCC Demand (Carib/Brazil)	3	7	10	14	17	20	24
UNITED STATES							
VLCC Demand (AG)	4	8	11	15	19	23	27
Suezmax Demand (WAFA)	4	7	11	14	18	21	25
Suezmax Demand (Carib/Brazil)	2	3	5	6	8	9	11

Source: Credit Suisse estimates.

VLCCS into China from WAFA have a multiplier of 1.5x on ton-miles versus the ME, while VLCCs into India from WAFA have a 2.5x multiplier versus the ME

European E&P in 2012

Ophir, Tullow, and Det norske top the list for 2012

In our European E&P coverage, we continue to favor attractive growth stocks with fundamental value and cash flow support and/or coupled with exploration catalysts in the right geological "postcodes." Funding ability is also likely to play a more pivotal role, especially if the current debt crisis were to deteriorate further. This thematic is also likely to continue to support M&A activity in the sector, as weaker players are acquired, either for cheap reserves or to facilitate project development (e.g., Premier's announcement of acquiring EnCore). We like Tullow Oil (O/P, TP 1776p), Premier Oil (O/P, TP 490p), Ophir Energy (O/P, TP 510p), Genel Energy (O/P, TP 1093p), and Det norske (O/P, TP NOK120/sh), which if combined in a portfolio basket offer a balance of cashflow support, funded growth/drilling and frontier exploration with some added layers of potential longer-term M&A optionality.

The major themes for 2012 in the European E&P space are expected to be as follows.

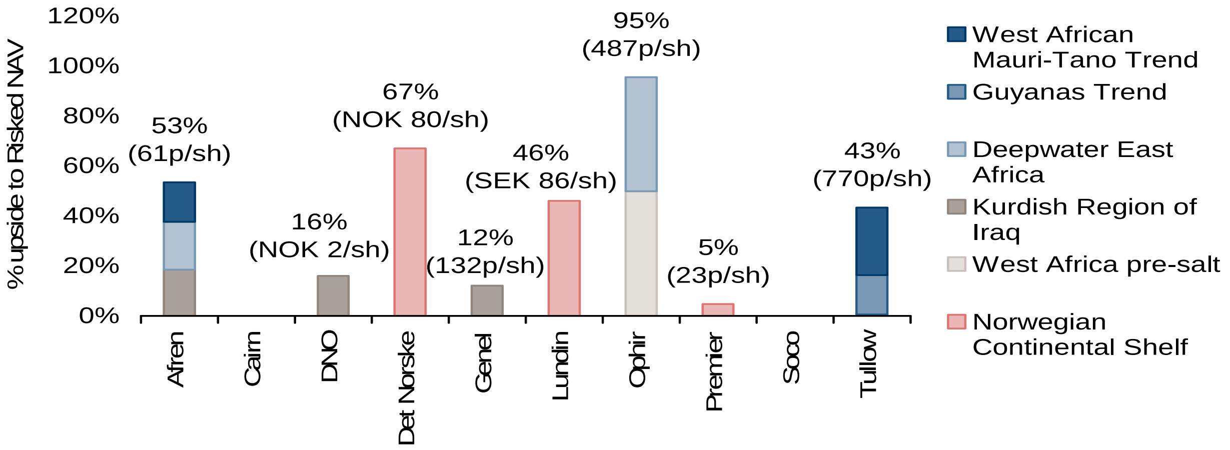
Exploration in the Right Geological "Postcodes"

Although oil prices and exploration activities remain high, we remain cautious on speculative exploration and continue to favor a portfolio basket of growth stocks that are well funded to carry out their 2012 drilling campaign in the right geological "postcodes."

With frontier exploration, the chance of geological success is low and historically has averaged c.10% (i.e., one successful well out of 10 wells). Tullow and Ophir have been outliers in our coverage. Tullow has achieved greater than 70% global exploration and appraisal success rate over the last several years, notably in Ghana, Uganda and French Guiana. Ophir has had 100% success rate in Tanzania from its three wells drilled so far.

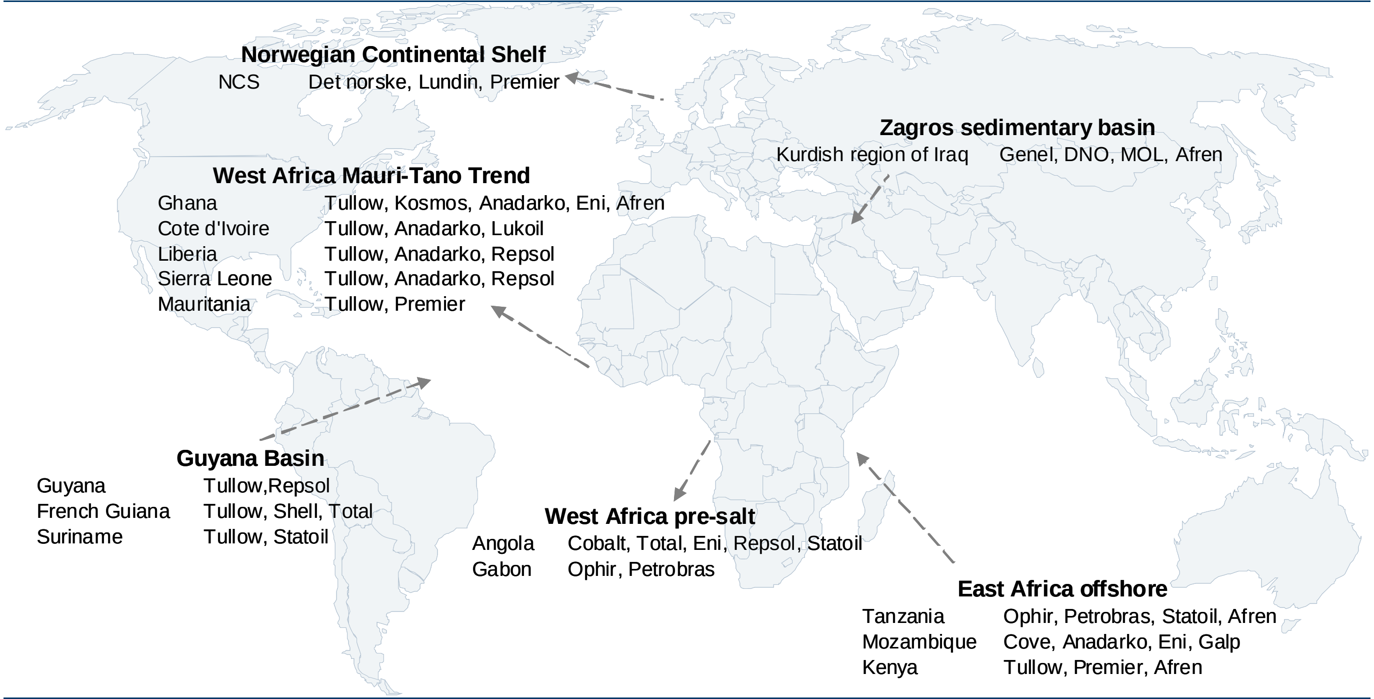
We continue to focus on the West African Mauri-Tano Trend where Tullow is looking to extend the Jubilee play. The Guyanas Trend on the South American side of the Equatorial Atlantic transform margin looks attractive after the Zaedyus discovery in French Guiana de-risked a huge new opportunity set. Deepwater East Africa will remain in focus as BG/Ophir will drill 5-6 wells in Tanzania by 2012-end, while Eni/Galp and Cove/APC continue drilling in Mozambique. Several near-term wells are planned in the Kurdish region of Iraq targeting the highly prolific Zagros sedimentary basin. We also highlight the Norwegian Continental Shelf as a reemerging exploration hotspot (Lundin/Det norske) after the recent Avaldsnes/Aldous discoveries. Although still early days for Pre-salt West Africa, this thematic could pick up momentum after Cobalt's wells results in Angola. We are not bearish on Greenland, but the inconclusive drilling results by Cairn do not provide much confidence going into 2012.

Exhibit 188: 2012 Drilling in Key Focus Areas—Blue Sky Upside to Risked NAV



Source: Company data, Credit Suisse estimates.

Exhibit 189: **European E&Ps—Key Exploration Focus Areas in 2012**


Norwegian Continental Shelf
NCS Det norske, Lundin, Premier
Zagros sedimentary basin
Kurdish region of Iraq Genel, DNO, MOL, Afren
West Africa Mauri-Tano Trend
Ghana Tullow, Kosmos, Anadarko, Eni, Afren
Cote d'Ivoire Tullow, Anadarko, Lukoil
Liberia Tullow, Anadarko, Repsol
Sierra Leone Tullow, Anadarko, Repsol
Mauritania Tullow, Premier
Guyana Basin
Guyana Tullow,Repsol
French Guiana Tullow, Shell, Total
Suriname Tullow, Statoil
West Africa pre-salt
Angola Cobalt, Total, Eni, Repsol, Statoil
Gabon Ophir, Petrobras
East Africa offshore
Tanzania Ophir, Petrobras, Statoil, Afren
Mozambique Cove, Anadarko, Eni, Galp
Kenya Tullow, Premier, Afren

Source: Credit Suisse Research.

West African Mauri-Tano Trend—Extending the Jubilee Play

This region continues to be Tullow's 'elephant' hunting ground as Tullow seeks to capitalize on its Cretaceous play breakthrough from offshore Ghana (the Tano-Ivorian Basin) to Mauritania. Although Tullow has had noncommercial discoveries in Sierra Leone (Venus and Mercury) and in Liberia (Montserrado-1 well), it was successful in proving a working hydrocarbon system. We are likely to hear more from Tullow and others over the next 12 months as they continue to drill several high impact wells over the next 12 months (Exhibit 190).

European E&Ps exposure to 2012 drilling: Tullow (+480p/sh or 27% blue sky upside to NAV) and Afren (+18p/sh or 16% blue sky upside to NAV).

Exhibit 190: **Near-Term Exploration Drilling in the West African Mauri-Tano Trend**

Country	Well / Prospect	Spud date	Gross unrisked resources, mmboe	Operator	Key partners
Ghana	Enyenra app. (DWT)	4Q	-	Tullow (49.95%)	Anadarko (18%), Kosmos (18%)
Liberia	LB-11 and 12 (2 wells)	4Q	-	Chevron (70%)	Oranto (30%)
Sierra Leone	Jupiter	4Q	250	Anadarko (55%)	Repsol (25%), Tullow (20%)
Cote d'Ivoire	Kosrou (CI-105)	1Q	550	Tullow (22.37%)	Anadarko (55%)
Cote d'Ivoire	Paon (CI-103)	1Q	420	Tullow (45%)	Anadarko (40%)
Ghana	Keta	1Q	325	Eni (35%)	Afren (35%), Mitsui (20%), GNPC (10%)
Ghana	Turonian/Cenomanian Deep (DWT)	2Q	320	Tullow (49.95%)	Anadarko (18%), Kosmos (18%)
Ghana	Teak-4 (WCTP)	2Q	-	Kosmos (30.9%)	Tullow (26.4%), Anadarko (30.9%)
Ghana	Sapele-1 (DWT)	2Q	160	Tullow (49.95%)	Anadarko (18%), Kosmos (18%)
Liberia	Strontium	2Q	450	Anadarko (57.5%)	Tullow (25%), Repsol (17.5%)
Liberia	Io	3Q	525	Anadarko (55%)	Repsol (25%), Tullow (20%)
Ghana	Cedrella-1 (WCTP)	2012	-	Kosmos (30.9%)	Tullow (26.4%), Anadarko (30.9%)

Source: Company data, Credit Suisse Equity Research.

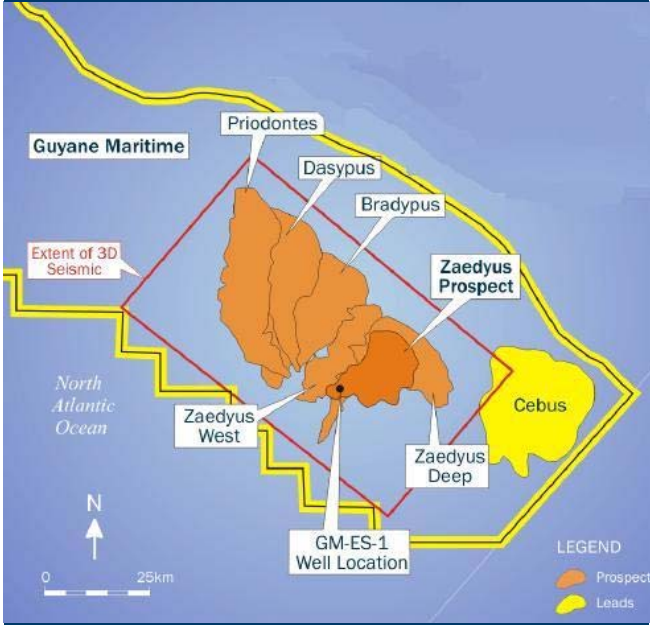
Guyana Basin—Huge New Opportunity Set Derisked

Tullow's Zaedyus discovery in French Guiana is of industry significance; it proved a working hydrocarbon system on the South American side of the Equatorial Atlantic transform margin. Tullow has been chasing this play concept here since its success with the Jubilee discovery in Ghana, on the African side of the passive margin. Prior to Zaedyus, there was no evidence of source and charge migration in the Guyana basin. With this now confirmed, Tullow has derisked a large opportunity set of potential oil prospects. Current drilling plans include two wells in the French Guiana acreage in 2012. Overall, Tullow and partners (Shell and Total) are looking to chase at least six turbidite fan prospects (excluding Zaedyus) in French Guiana. Tullow targets to spud the Jaguar well in Guyana in December targeting 700mmboe gross resource potential. The B47 block in Suriname is a 70% Tullow block (30% Statoil) and a 3D seismic survey is planned across the Golianthberg and Voltzberg leads before drilling commences.

With evidence of source and charge migration now confirmed in the Guyana basin, a large number of prospects have been derisked for Tullow

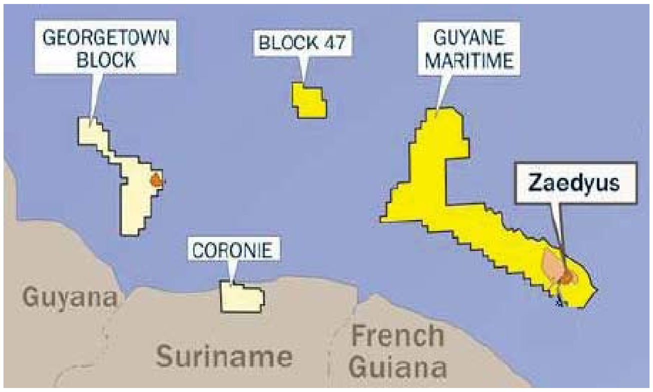
European E&Ps exposure to 2012 drilling: Tullow (+279p/sh or 16% blue sky upside to NAV)

Exhibit 191: **Six Jubilee-Sized Prospects in French Guyana**



Source: Tullow Oil.

Exhibit 192: **Tullow's Guyana Basin Acreage**



Source: Tullow Oil.

East Africa Deepwater—Positive Momentum Continues

Deepwater East Africa will remain in focus over the next couple of years as an emerging gas province. In Tanzania, Ophir and BG are set to commence their 5-6 well drilling campaign targeting sufficient foundation volumes to underpin a two-train LNG development. In Mozambique, talks of a multi-train LNG development (up to six trains) are ongoing as Cove/APC and Eni/Galp continue exploration and appraisal activities.

East Africa could become LNG's next Qatar

Continued significant industry interest will also drive consolidation in the region. Smaller E&Ps will look to monetize the gas resources (complete sale or partial farm-out to fund LNG development). Ophir has highlighted its intention to monetise assets as early as H2 2012, while Cove has recently opened a data room to certain parties that have shown interest in its Mozambique acreage and is also discussing off-take agreements in the Asian and European markets.

European E&Ps exposure to 2012 drilling: Ophir (+233p/sh or 46% blue sky upside to NAV), Afren (+22p/sh or 19% blue sky upside to NAV) and Tullow (+10p/sh or 1% blue sky upside to NAV).

Kurdish Region of Iraq—One of the Last 'Underexplored' and 'Easy' Oil Provinces

Kurdistan is highly prospective if above-ground issues can be resolved

The Kurdish region of Iraq is situated within the highly prospective Zagros sedimentary basin and is widely seen as one of the last 'underexplored' and 'easy' oil provinces. The basin is highly prolific with several giant discoveries such as the Kirkuk, Tawke, Taq Taq and Shaikan oil fields, but it also contains a number of large gas-condensate discoveries/fields (Khor Mor, Chemchemal, Miran). Several exploration and appraisal wells are planned in the Kurdish region of Iraq in the near term. We highlight below the key wells planned in the region.

European E&Ps exposure to 2012 drilling: Afren (+21p/sh or 18% blue sky upside to NAV), DNO (+NOK 2.0/sh or 16% blue sky upside to NAV) and Genel Energy (+132p/sh or 12% blue sky upside to NAV).

Exhibit 193: **Near-Term Wells Planned in the Kurdish Region of Iraq**

Spud date	Well/ Prospect	Well type	PSC	Companies
1Q11	Bekhme-1	Exploration	Akri Bijeel	MOL (80%), Gulf Keystone (20%)
2Q11	Shaikan-4	Appraisal	Shaikan	Gulf Keystone (75%), MOL (20%), Texas Keystone (5%)
3Q11	Peshkabir-1	Exploration	Tawke (West Dohuk)	DNO (55%), Genel (25%), KRG (20%)
3Q11	Mil Qasim-1	Exploration	Garmian	WesternZagros (40%), Not assigned (40%), KRG (20%)
3Q11	Miran West-3	Appraisal	Miran	Heritage (56.25%), Genel (18.75%), KRG (25%)
4Q11	Shaikan-5	Appraisal	Shaikan	Gulf Keystone (75%), MOL (20%), Texas Keystone (5%)
4Q11	Ber Bahr-1	Exploration	Ber Bahr	Gulf Keystone (40%), Genel (40%), KRG (20%)
4Q11	Jebel Simrit-2	Exploration	Ain Sifni	Hunt Oil (60%), Afren (20%), KRG (20%)
4Q11	Shaikan-6	Appraisal	Shaikan	Gulf Keystone (75%), MOL (20%), Texas Keystone (5%)
4Q11	Aqra-1	Appraisal	Akri Bijeel	MOL (80%), Gulf Keystone (20%)
4Q11	Bakrman-1	Exploration	Akri Bijeel	MOL (80%), Gulf Keystone (20%)
4Q11	Kurdamir-2	Exploration	Kurdamir	Talisman (40%), WesternZagros (40%), KRG (20%)
1Q12	Shaikan-7	Appraisal	Shaikan	Gulf Keystone (75%), MOL (20%), Texas Keystone (5%)
1Q12	Baranan-1	Exploration	Baranan	Talisman (100%)
1Q12	Miran East	Exploration	Miran	Heritage (56.25%), Genel (18.75%), KRG (25%)
2Q12	Gulak-1	Exploration	Akri Bijeel	MOL (80%), Gulf Keystone (20%)
2Q12	Atrush-2	Appraisal	Atrush	Aspect Energy (53.2%), ShaMaran (26.8%), Marathon (20%)
2H12	Chia Surkh-10	Exploration	Chia Surkh	Forbes (40%), Genel (20%), Petoil (20%), KRG (20%)
2H12	Taq Taq Deep	Exploration	Taq Taq	Genel (44%), Addax (36%), KRG (20%)
2H12	Kewa Chirmila	Exploration	Taq Taq	Genel (44%), Addax (36%), KRG (20%)
2012	Tawke Deep	Exploration	Tawke	DNO (55%), Genel (25%), KRG (20%)
2012	Arbat	Exploration	Arbat	ShaMaran (60%), KRG (40%)
2012	Jebel Simrit-3	Exploration	Ain Sifni	Hunt Oil (60%), Afren (20%), KRG (20%)
2012	Jebel Simrit-4	Exploration	Ain Sifni	Hunt Oil (60%), Afren (20%), KRG (20%)

Source: Company data, Credit Suisse estimates.

Norwegian Continental Shelf—Reemerging as an Exploration Hotspot

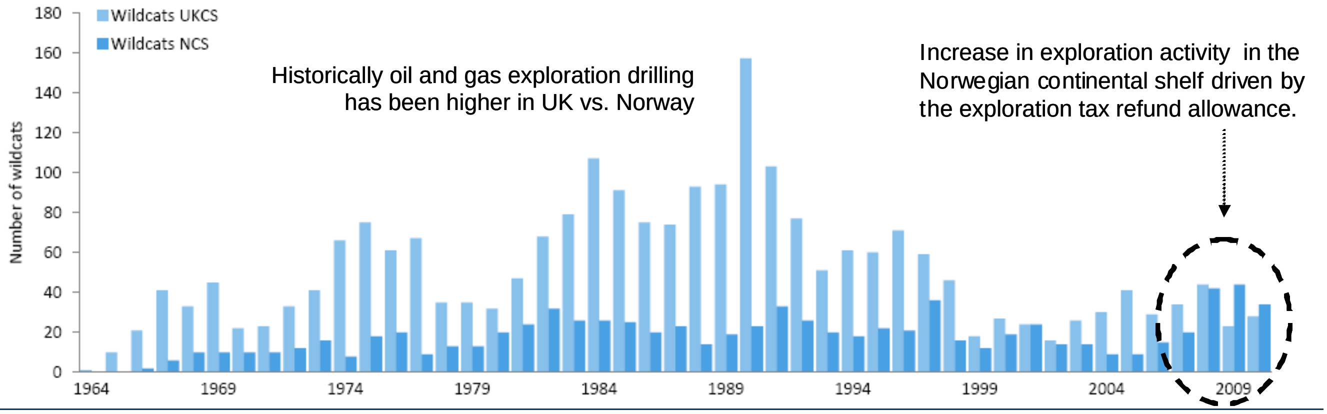
Who said the North Sea was dead—third largest find was made in 2011

The combination of a prolific hydrocarbon basin, an attractive Norwegian fiscal regime that incentivises investment via generous tax offsets, and opening up of new areas has contributed to the reemergence of the Norwegian Continental Shelf (NCS) as an exploration hotspot, in our view. The recent Avaldsnes/Aldous discovery (mid-case P50 volumes of 2.5bn boe) is one of the largest offshore discoveries in 2011 globally. It is now the third largest discovery ever made in the NCS region.

Extensive unopened areas still exist on the NCS. No new areas have been opened for E&P activities on the NCS since 1994; however an opening process has started for the waters off Jan Mayen and the area at the southern end of the Barents Sea East. The Norwegian Petroleum Directorate has estimated the total remaining undiscovered resources in the region as 16bnboe.

European E&Ps exposure to 2012 drilling: Det norske (+NOK 80/sh or 67% blue sky upside to NAV), Lundin (+86 SEK/sh or 46% blue sky upside to NAV) and Premier (+23p/sh or 5% blue sky upside to NAV).

Exhibit 194: Exploration Wells Spudded on the NCS and the UKCS from 1964 to 2010



Historically oil and gas exploration drilling has been higher in UK vs. Norway

Increase in exploration activity in the Norwegian continental shelf driven by the exploration tax refund allowance.

Source: Norwegian Petroleum Directorate, Credit Suisse Research.

Funding Is Not a Concern (for Now)

E&P is a very capital intensive industry and a company's funding ability is crucial to unlock value. Funding can be from internal cashflows and/or from external means (new equity, farm-outs/divestments, and debt facilities).

Premier and **Tullow** offer a balance of internal cashflow support and sufficient headroom on existing debt facilities (see Exhibit 195.) Premier has one of the strongest balance sheets in the Euro E&P space and can continue to leverage its balance sheet to make attractive strategic acquisitions to facilitate project development (e.g. proposed EnCore acquisition). Tullow's balance sheet continues to evolve, and with the $2.9bn of Uganda farm-out proceeds expected shortly, we believe Tullow will be in a comfortable financial position to reinvest into exploration.

Genel has c$1.9bn of cash that could generate superior returns from M&A in the near term especially if the current debt crisis were to deteriorate further. Genel's strategy is to manage its existing operations in the Kurdish region of Iraq on a cash flow neutral basis.

Ophir has c$410m of cash currently that we think is sufficient to fund its 2012 drilling plan and we expect Ophir to need additional financing by early 2013. Ophir's management has been clear in the asset monetization strategy and farm-out of its core assets in Equatorial Guinea and Tanzania remains one of the likely options.

For **DNO**, there is still no clarity on timing of the next export payment from the Kurdistan Regional Government. We expect DNO to maintain its cautious stance of spending on development projects in the Kurdish Region of Iraq and to focus on development of RAK assets (assuming the merger is complete).

Det norske's near-term exploration and development program is fully funded via an exploration debt facility ($818m) and corporate lending facility($500m) with Norwegian banks.

Regarding the development of its major projects in the medium term, we think that Det norkse can secure additional debt based on its 2P resource base *(in addition to the existing debt facilities)* and increase its net debt to up to a $1bn by 2014. It might also have to raise around $700m of additional cash, either through an equity issue or an asset deal; the value of Det norske's stake in its two major discoveries*(Draupne and*

Aldous/Avaldsnes), which could feature in a possible asset divestment, is around $1.5bn, in our opinion.

2012 funding looks sufficient

Lundin has sufficient headroom currently, but would require additional funding to develop its Luno and Avaldsnes/Aldous discoveries. We think Lundin's ability to fund these projects is not a major concern and Lundin can meet its capex requirements from a combination of 1) internally generated funds; 2) refinancing its existing reserves based lending facility; and 2) issuing high yield bonds.

Cairn Energy will retain c$1.2bn of cash for further growth opportunities following the Cairn India stake sale to Vedanta and an announced $3.5bn payout to shareholders (in Q1 2012). Cairn remains well funded but uncertainty remains around Cairn's spending plans as it does not intend to use this cash for further Greenland exploration. Cairn will rely on the wider industry to determine the availability of funding (via acreage farm-out and cost carry) for the 2012 Greenland drilling program.

Soco is currently in a comfortable net cash position and is looking to strengthen its exploration portfolio in Southeast Asia and Africa. Around 85% of Soco's valuation is dominated by its TGT field in Vietnam, and the near term operational performance of this complex field will be a key driver of future cashflows.

Afren has so far disappointed in meeting its operational targets on the Ebok field in Nigeria. Ebok's ramp-up to plateau production has been delayed six times so far. Although the delay was not caused by subsurface issues and Afren is on track to meet the 35kbpd exit rate from Ebok by 2011-end, it is dependent on strong cashflows from Ebok in order to de-lever its balance sheet. We believe a stable Ebok production in 2012 would be important for Afren, if the current debt crisis were to deteriorate further and the banks scale back their reserve based lending facility.

Exhibit 195: **European E&Ps—Cash Available vs. Cash Required for 2012**

	Afren	Cairn	Det Norske	DNO	Genel	Lundin	Ophir	Premier*	Soco	Tullow
	$m	*$m*	*$m***	*$m***	*$m*	*$m*	*$m*	*$m*	*$m*	*$m*
Cash available										
Cash (end-2011E)	431	4,700	381	247	1,850	176	380	357	229	504
2012 CFO	838	-13	67	395	397	737	-23	874	372	1,761
Current debt facility headroom	239	0	699	0	0	740	0	743	0	945
Others (divestments)	0	0	0	0	0	0	0	0	0	2,283
Total cash available	**1,508**	**4,687**	**1147**	**642**	**2,247**	**1,653**	**357**	**1,974**	**601**	**3,210**
Cash required										
2012 capex	500	700	576	102	210	990	286	1,050	150	1,800
2012 debt repayment	84	0	368	43	0	0	0	201	0	395
Others (acquisitions, dividends)	200	3,500	-	0	0	0	27	0	0	72
Total cash required	**784**	**4,200**	**945**	**145**	**210**	**990**	**313**	**1,251**	**150**	**2,267**
Excess cash	**724**	**487**	**202**	**498**	**2,037**	**663**	**44**	**723**	**451**	**943**

*Source: Company data, Credit Suisse estimates. Note: * Assuming EnCore shareholders opt for Premier's new share issue at 338.7p/sh (Closing share price on 14th Dec 2011 was 366p/sh).*

Funding ability is likely to play a more pivotal role, especially if the current debt crisis were to deteriorate further. Even companies with cash-generating assets could be forced to curtail capital expenditure budgets in the face of lower borrowing bases or a lessened ability to service existing corporate facilities. We highlight the current debt facilities of European E&Ps in Exhibit 196.

Exhibit 196: European E&Ps—Current Debt Facilities

	Debt facility size	Maturity	Banks
Afren	$450m	2015*	BNP Paribas, Citi, and Natixis
	$200	2012	BNP Paribas and VTB
	$50	2013	-
	$500m	2016	Senior secured notes
Cairn	-	-	
Det Norske	$818m	2012	DnB NOR
	$500m	2015	DNB, Nordea and SEB
DNO	c.$253m	2012	Various bond loans
	c.$245m	2016	Various bond loans
Genel	-	-	
Lundin	$740m	2014	Syndicate of 19 international banks led by BNP Paribas
Ophir	-	-	
Premier	$175m	2012	Syndicate of 6 banks with Lloyds as the agent bank
	$300m	2015	Lloyds (agent bank) and Mediobanca
	$457m	2015	Syndicate of 17 international banks
	£399.5m	2015	Syndicate of 14 international banks
Soco	-	-	
Tullow	$650m	2011	Syndicate of banks including BNP Paribas, Bank of Scotland, The Royal Bank of Scotland, Standard Chartered Bank, Lloys TSB Bank, and Credit Agricole Corporate and Investment Bank
	$3,450m	2015	
	$300m	-	

*Source: Company data. Note: * Repayments commence 2012 through 2015.*

EEMEA Oil & Gas in 2012

A cautious outlook for Russia; Novatek and Eurasia Drilling preferred; a favorable outlook on Sasol

Russian oil & gas companies dominate the EEMEA energy space, with Sasol, MOL, PKN, Tupras and KMG EP completing the sector. Broadly speaking, we have a cautious outlook on the Russian energy companies, with the exception of NOVATEK (O/P, tgt $175) and Eurasia Drilling (O/P, tgt $32.50) as we believe that these two companies have stand-alone structural growth investment cases that will outweigh the concerns on the macro-environment, cost inflation and stalling tax reform. We have a favorable view on Sasol (O/P, tgt ZAR457) given improving execution and a growing acceptance of GTL technology as a way to monetise the huge gap between gas and oil calorific equivalent prices, particularly in North America and the Middle East. We also like the downstream focused MOL principally due to its interesting exploration exposure to Kurdistan.

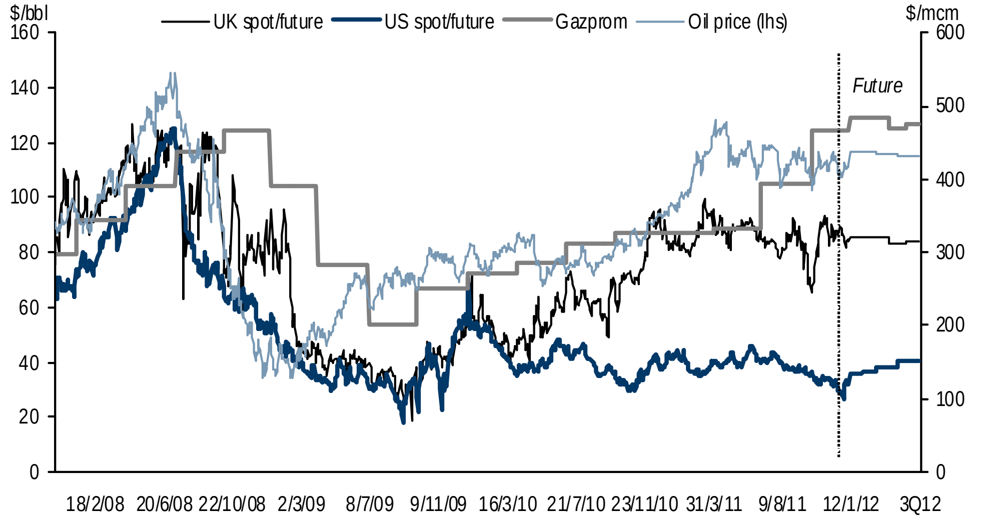
The major themes for 2012 in the EEMEA oil and gas sector are expected to be as follows.

Big Differential in Gas Prices to Continue

More assertive push for take-or-pay renegotiation on European gas contracts

The gap between European spot gas prices and oil-linked prices has widened to record levels in late 2011 given weak demand due to warm weather, weak economic activity and the uncompetitive nature of gas-fired power generation in Europe combined with the full return of Libyan gas supplies. We expect that European utilities will push ever more aggressively to renegotiate take-or-pay contract terms, with some existing arbitration cases reaching conclusion by 3Q/4Q12. Having said that, we expect that Gazprom will sustain minimum take or pay volumes in 2012 unless European demand collapses.

Exhibit 197: Gas Price Comparisons



Source: The BLOOMBERG PROFESSIONAL Service, Credit Suisse estimates.

We believe that the EU may also attempt to take Gazprom to the European Court of Justice over failure to adhere to the Third Energy Package. Lack of progress may force the EU to pursue Gazprom's partners in the Nordstream project (GDF Suez, Wintershall, E.ON and Gasunie). Ultimately, we believe that, in an energy context at least, relations between Russia and the EU will remain tense as the former seek to sustain ownership of East European networks and as the latter continue to push the liberalization agenda.

NOVATEK to Enter the Export Market?

We believe that Gazprom’s failure to settle price disagreements with its European customers may open the door for NOVATEK to begin exporting gas to Europe, with first export volumes potentially delivered by 3Q12. We suggest that NOVATEK would be happy to sell gas at European spot prices as we calculate that netbacks would be over 3x what NOVATEK earns on domestic gas sales.

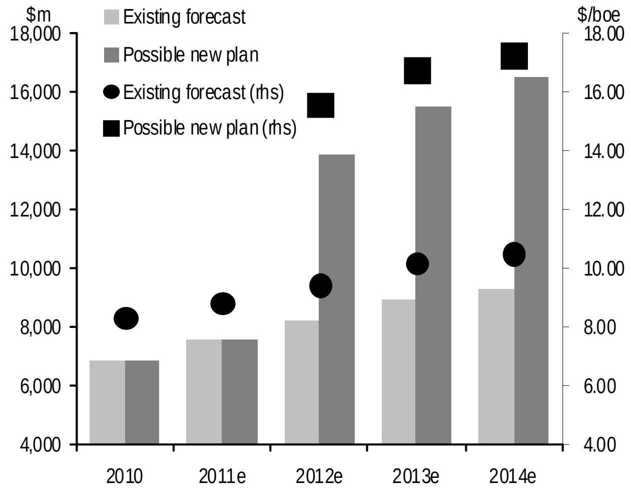
In addition, we expect that NOVATEK will secure a second partner for the Yamal LNG project (most likely Qatar Petroleum) and achieve FID before the end of 1Q12, ahead of schedule. We also expect NOVATEK to announce further acquisitions of domestic gas assets at very attractive prices in 2012, in particular Nordgas and Purgas, giving NOVATEK the flexibility to consider export opportunities.

Oil Companies Boost Capex

Hike in capex will compress free cash flow at the Russian majors

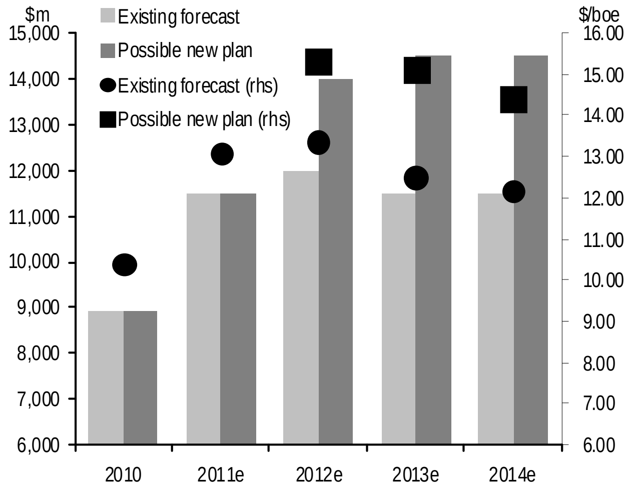
Both LUKOIL and Rosneft will present "new" strategies in early 2012 in which we expect they will dramatically increase medium-term capex plans (by 50-100%) as refinery upgrade programs accelerate, new greenfield development plans are presented and the companies increase their investment in more advanced upstream technology and processes. This capex boost is an important element of our positive view on Eurasia Drilling—Russia's brownfield provinces are mature, and sustaining production, or rather mitigating decline, will be dependent on more aggressive drilling programs. Independent energy consultants, Renergy, have suggested that Russian companies will need to increase onshore drilling volumes by 9% p.a. just to keep production flat.

Exhibit 198: **LUKOIL Capex**



Source: Company data, Credit Suisse estimates.

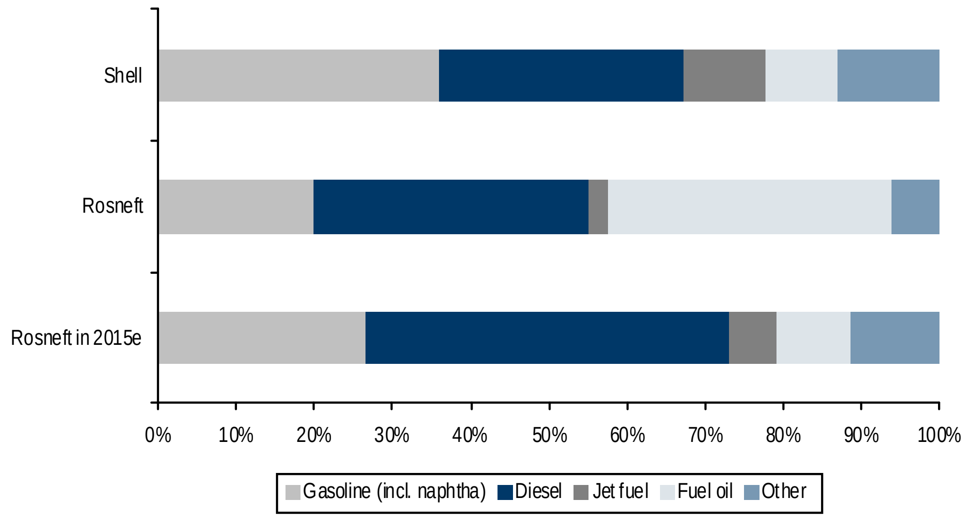
Exhibit 199: **Rosneft Capex**



Source: Company data, Credit Suisse estimates.

In LUKOIL's case, we believe that the bulk of the incremental investment will be in accelerating the adoption of modern upstream technologies in an attempt to stabilise brownfield production in Russia. In Rosneft's case, we think the bulk of increased capex will be focused on refinery upgrades (see below) and new East Siberian developments.

Exhibit 200: Rosneft v Shell—Refined Product Output



Source: Company data, Credit Suisse estimates.

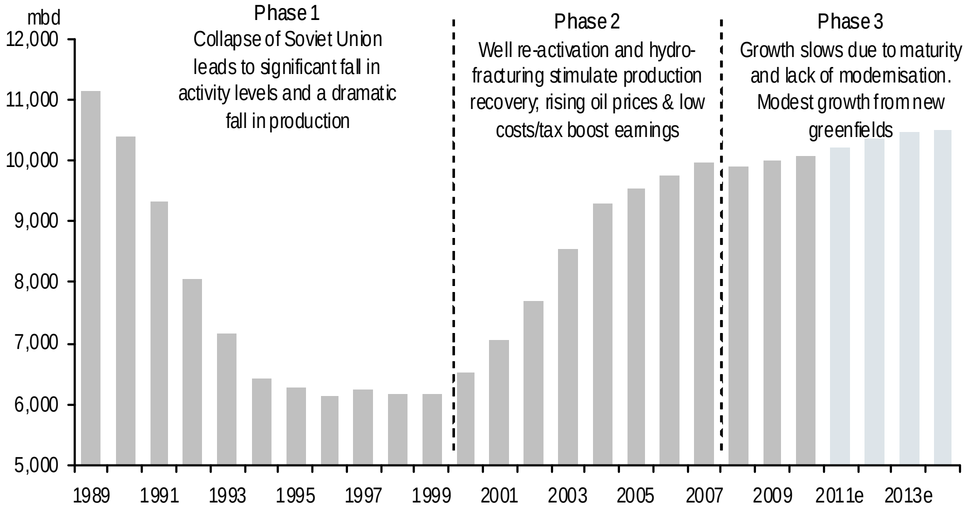
Little Movement on Tax but Oil Production Should Be Stable

Slightly higher Russia production in 2012 despite only partial implementation of “60/66” tax regime

2011 saw partial implementation of the much anticipated new “60/66” regime, in that the harmonization of export duties on petroleum products at 66% of the crude export duty rate has been fully adopted while the cut in the marginal crude export duty rate to 60% will be decided on a month-by-month basis. We expect that there may be more discussion of profit-based taxation for new developments, but the terms are likely to remain unclear and the Ministry of Finance is likely to avoid specifying a date when it is to be implemented. Budget pressures and tensions around the 2012 elections suggest that there will be no let up on oil and gas taxation, and if anything, we believe that energy industry taxation could even be increased.

Despite this we expect oil production to marginally increase in 2012 and grow to roughly 10.5mbpd by 2014, where we expect oil production to remain until 2017. This is due to a number of new fields coming onstream (Suzun, Tagul, Yurubcheno Tokhomskoye) and some ramping up further (Vankor, Talakan, Verknechonsk, Uvat, Kammenoye) as well as some stabilization in brownfield production due to more widespread application of modern technologies.

Exhibit 201: **Russian Oil Production**



Source: CDU-TEK, Credit Suisse estimates.

Iraq in 2012—Infrastructure and Politics

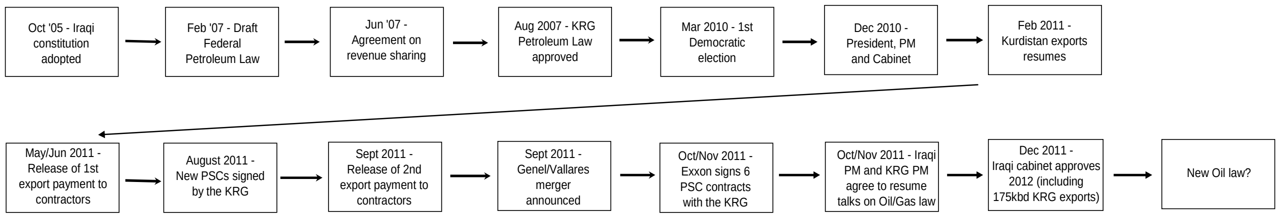
Iraq/Iraqi Kurdish Region

Iraq and the Kurdish Region of Iraq are seen as the last 'easy' onshore 'underexplored' oil provinces in the world. Iraq is estimated to hold recoverable reserves of 143bn bbls of oil, while the USGC estimates the Kurdish Region of Iraq to hold 40bn bbls of oil and 60tcf of gas. While the attractiveness underground is luring many oil companies, in particular most recently Bigger Oil entering the Kurdish Region of Iraq, the issues are above the ground between the Government of Iraq (GOI) and the KRG, in particular around the twin issues over Oil (resource rights) and Kirkuk (territorial rights).

December headlines have not made for comfortable reading; however some incremental progress is being made

While Iraqi PM has not quite delivered on the promises to the KRG as a condition to be reinstated as PM following the March 2010 elections, we generally feel that progress since the creation of a unified government in December 2010 has still been encouraging. These are very interesting times and political developments are uncertain, but 2012 will provide many new insights following **(a)** Exxon's recent move into the Kurdish Region of Iraq and **(b)** the withdrawal of the US troops. While we expect no near-term resolution on the Oil and Gas Law, this does not mean we cannot get excited about the Kurdish Region of Iraq so long as the KRG continues to make incremental steps forward.

Exhibit 202: Timeline of Events


Oct '05 - Iraqi constitution adopted
Feb '07 - Draft Federal Petroleum Law
Jun '07 - Agreement on revenue sharing
Aug 2007 - KRG Petroleum Law approved
Mar 2010 - 1st Democratic election
Dec 2010 - President, PM and Cabinet
Feb 2011 - Kurdistan exports resumes
May/Jun 2011 - Release of 1st export payment to contractors
August 2011 - New PSCs signed by the KRG
Sept 2011 - Release of 2nd export payment to contractors
Sept 2011 - Genel/Vallares merger announced
Oct/Nov 2011 - Exxon signs 6 PSC contracts with the KRG
Oct/Nov 2011 - Iraqi PM and KRG PM agree to resume talks on Oil/Gas law
Dec 2011 - Iraqi cabinet approves 2012 (including 175kbd KRG exports)
New Oil law?

Source: Credit Suisse Research.

Rationale for Investing in Iraq/Kurdish Region of Iraq

Iraq is widely estimated to have the fourth largest proven reserves in the world, and given the underexplored nature of the country, this estimate is likely to rise once its oil infrastructure, debilitated by over 30 years of war and sanctions, is brought up to standard. Iraq is estimated to hold 143bn bbls of oil and the US Geological Survey estimates that the Kurdish region of Iraq could hold as-yet undiscovered hydrocarbons of c40bn bbls of oil and 60tcf of gas.

Since the discovery of the giant Kirkuk field in 1927, Iraq has only enjoyed around 15 years of intensive exploration efforts. This underexplored nature is attracting many oil companies, for example most recently large IOCs including Exxon and Repsol into the Kurdish region of Iraq. The large Taq Taq, Tawke and Shaikan discoveries in the Kurdish region of Iraq are examples of what can be found in the 'under-explored' Iraqi Kurdistan.

The rationale for Exxon signing six new exploration contracts with the KRG is difficult to gauge. Strategically, Exxon takes a very long-term view when entering a region. That said, we think it could be significant not just in terms of what it means for PSCs, but also because of what that in turn could mean for the appeal of oil contracts in the south. In some ways, this could be seen as undermining the historical position in the first two licensing rounds—i.e., that IOCs would accept unattractive TSCs for the right to bid in the future and more attractive contracts in the south—and questioning the investment case in the south.

Iraqi/Kurdish Issues

A federal oil and gas law needs to resolve disputes between the Kurdish Regional Government and the Government of Iraq

A federal Oil and Gas law is needed to lay out a framework for the legitimacy of the Kurdish oil contracts. The legislation, mandated by the 2006 Constitution, has become stagnant since 2007 owing to the dispute between the KRG and Government of Iraq (GOI) over the twin issues of oil (resource rights) and Kirkuk (territorial dispute). Until recently, Big Oils have taken a less risky path by investing in southern Iraq, with reward commensurate with risk—i.e., less attractive TSCs (for producing assets) and less upside. However the TSC approach adopted by former Oil Minister Sharistani coupled with the institutional voids in Baghdad is now visibly hindering operational efficiency. Iraq should look towards the more conducive policies adopted by the KRG if it intends to grow production significantly

Centralism versus Federalism

The key question and fundamental disagreement between Baghdad and Erbil is whether Iraq should be a federal or a more centralized country in addition to a dispute over territorial boundaries (including Kirkuk). The issue is that federalism is seen as a precursor to the break-up of the state. In contrast, Kurdish leaders view the ability to maintain a semi-autonomous region as a pre-condition to their continued union with Iraq.

Iraq’s 2006 Constitution explicitly declares Iraq a federal state, recognises the status of the KRG and even declares regional laws superior to federal ones, but calls for a law to establish a more precise balance of powers in the oil sector. The constitution is less clear in other places such as those relating to the oil and gas sector and both the GOI and the KRG have pursued oil developments according to their respective interpretations of the relevant articles.

This is the origin of the current tensions between the GOI and the KRG. They disagree over:

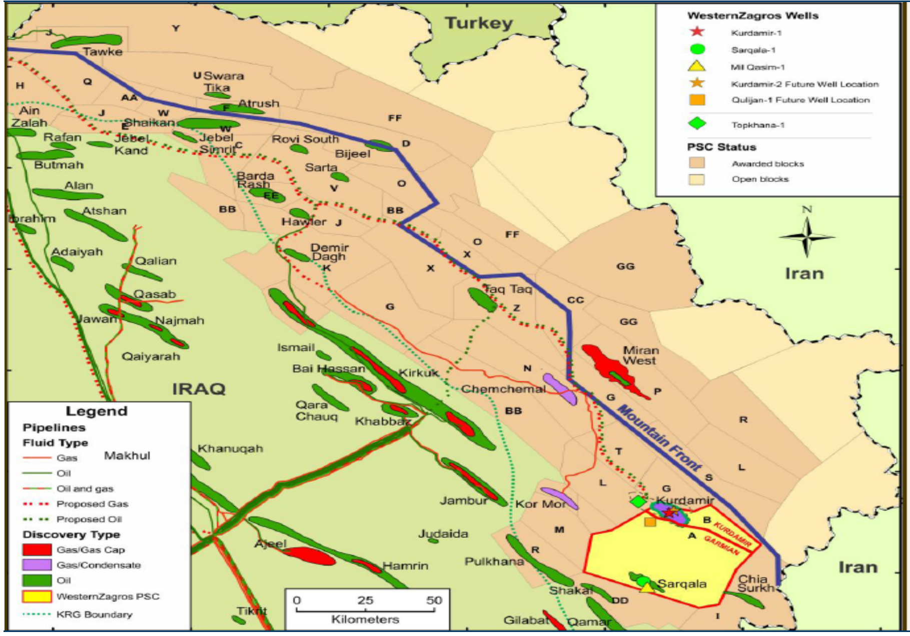
- **(a)** which entity has the right to develop resources in the region,
- **(b)** the appropriate contracting mechanism for the development of Iraq’s resources (TSCs signed in Southern Iraq versus PSCs signed in the Kurdish Region of Iraq), and
- **(c)** other matters related to how the budget is handled and national oil revenues divided.

Important distinction between ‘existing’ and ‘new’ fields

The Iraqi Constitution, which came into effect in 2006, provides that the ‘*management of oil and gas extracted from present fields*’ is to be undertaken jointly between the Iraqi Government and the producing governorates and regional governments. In other words, the KRG interpreted this as the GOI having the primary authority over ‘Existing fields’ (producing/discovered fields), while ‘New fields’ (exploration) fall into the purview of the regions and thus can be developed according to Kurdish decisions independent from the GOI.

With this, the KRG has signed in total some 40 PSCs with international oil companies for ‘New fields’ (exploration). The Iraqi Central government consistently declared these PSCs unconstitutional and blacklists any oil company exposed to the Kurdish region of Iraq for any licensing rounds in the southern region (e.g., Hess, Repsol, Talisman, Marathan Oil).

Exhibit 203: Regional Oil and Gas Fields



	Block	Operator
A	**Garmian**	**WesternZagros**
B	**Kurdamir**	**Talisman**
C	Ain Sifni / K8	Hunt
D	Akre-Bijeel	MOL / Kalegran
E	Al Qush	Komet
F	Atrush	Gen. Expl. Partners
G	Bazian / Sangaw South	KNOC
H	Bina Bawi	PetroQuest
I	Chia Surkh	Longford
J	Erbil	DNO
K	Hawler	Norbest
L	K39/K9 Baranan	Talisman
M	K42	Oilsearch
N	KorMor	Dana Gas
O	Harir /Safeen	Marathon
P	Miran	Heritage
Q	Central Dohuk	Murphy
R	Pulkhana/Arbat	ShaMaran
S	Qarah Dagh	Niko
T	Sangaw North	Sterling
U	Sarsang	Hillwood / HKN
V	Sarta/Rovi	Reliance
W	Shaikan/Sheikh Adi	Gulf Keystone
X	Shorish/Mala Omar	OMV
Y	Sindi-Amedi	Perenco
Z	Taq Taq	TTOPCO
AA	Ber Bahr	Genel Energi
BB	Kepco Study Areas	KEPCO
CC	Khalakan	Gas Plus
DD	Shakal	Prime Natural Resources
EE	Barda Rash	Afren
FF	Dinarta/Shakrok	Hess
GG	Qala Dze/Piramigrun	Repsol

Source: Western Zagros.

PSC versus TSC—Valuing a Barrel

PSC barrels worth $4.7/bbl versus TSC barrels worth $1.0/bbl; PSC's would lead to greater overall investment in Iraq and hence greater government revenues/economic growth

We provide sensitivities in the event the PSCs are renegotiated and brought in line with the TSCs offered to the international oil companies in Southern Iraq. This is not our base case and we view it as unlikely; we highlight here the KRG's powerful position in the government, which is likely to lead to a veto to such propositions, while the kind of terms offered in the south for exploration assets in the north could discourage investment and jeopardise the oil industry. We think oil companies invested in the Kurdish region of Iraq will eventually be rewarded/validated with the better economics, even if the ultimate solution may not be a PSC in name.

We have calculated the net present value for the Tawke and Taq Taq fields based on our understanding of the Iraqi TSCs. As with the second round licensing amendment, no baseline production is assumed, and all production is considered incremental.

Exhibit 204: Kurdish Region of Iraq PSC vs. Southern TSC—Comparing the Economics

Kurdish region of Iraq PSC (Taq Taq and Tawke producing fields)		Southern TSC ($2/bbl remuneration fees)	
Description	Production Sharing Contract	Description	Technical Service Contract
Remuneration	Cost recovery plus Profit Oil share (10%-38%) based on "R" Factor	Remuneration	Cost recovery plus fixed $/bbl service fee (c$2/bbl)
Reserves	Bookable	Reserves	Not bookable
Field NPV/boe	$4.7-$4.8/boe	Field NPV/boe	$0.9-$1.0/boe
Government take	87-91%	Government take	98%

Source: Credit Suisse estimates; Note: based on 12% WACC and $90/bbl l-t Brent.

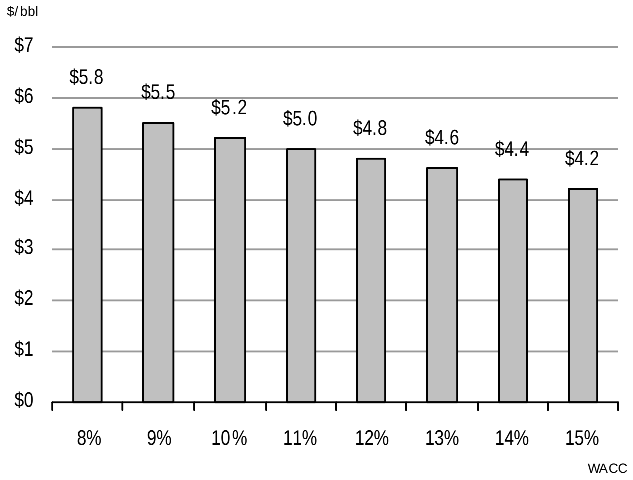
Fields awarded during Iraq's first and second licensing rounds in 2009 had remuneration fees ranging from $1.15/bbl (for West Qurna-2 field) to $6.0/bbl (for Najma field). The bigger fields (Rumaila, West Qurna-1, West Qurna-2 and others) had lower remuneration fees ranging between $1.15/bbl and $2.0/bbl, while the smaller fields (Najma, Qayara, Badra) had higher remuneration fees ranging between $5.0/bbl and $6.0/bbl. The higher remuneration fees for smaller fields imply the greater development risks associated with them. It is important to highlight that 'New Fields' (exploration) instead of 'Existing Fields' (development/discoveries), on which the TSCs are based, are likely to be rewarded with higher remuneration fields, to be more reflective of risk. The fourth licensing round for exploration blocks in southern Iraq should provide more color on this.

Exhibit 205: 1st/2nd Iraqi Licensing Round Remuneration Fees

Field	Partners	Fee ($/bbl)	Plateau commitment
Rumaila	BP/CNPC	2.00	2850
West Qurna-1	XOM/Shell	1.90	2325
Zubair	Eni/Oxy	2.00	1125
Majnoon	Shell/Petronas	1.39	1800
Halfaya	CNPC/Petronas	1.40	535
Qayara	Sonangol	5.00	120
West Qurna-2	Lukoil/Statoil	1.15	1800
Badra	Gazprom/TPAO	5.50	170
Gharaf	Petronas/Japex	1.49	230
Najma	Sonangol	6.00	110

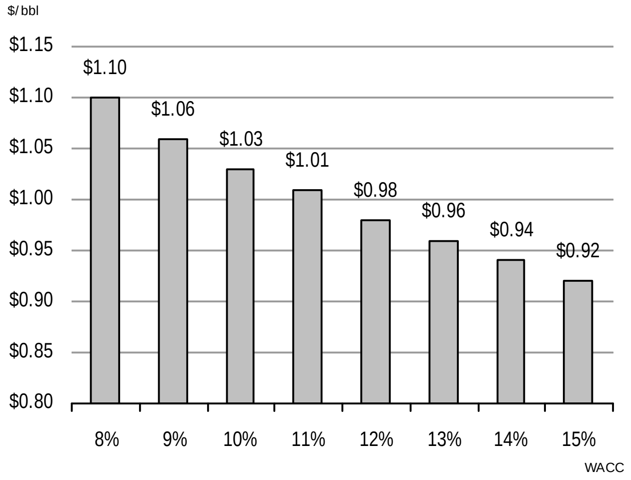
Source: Company data.

Exhibit 206: PSC at Different WACC



Source: Credit Suisse estimates.

Exhibit 207: TSC at Different WACC



Source: Credit Suisse estimates.

Evolution—2007–2011

The Iraqi cabinet approved a draft oil and gas (for centralism) legislation in 2007, but the parliament supported another (federalism) and thus failed to pass a new oil and gas law. With this, the KRG passed its own legislation (Kurdish Oil Law in August 2007) and proceeded to award licenses to IOCs within its boundaries. The implication of this impasse was significant—the KRG was largely unable to export production as the GOI prevented it from using federal infrastructure for export. The Kurdish region of Iraq is landlocked and export infrastructure is controlled by the federal government. This means once Kurdish oil is supplied into the export pipeline, it comes under the control of the federal government via SOMO (responsible for export sales).

As Kurdish votes become crucial to the establishment of a parliamentary majority, their power has increased

After years of no progress, the March 2010 election created a situation which pushed the KRG and the GOI closer, in particular after nine months of stalemate following the elections it became clear that no government could be formed without the two principal Kurdish parties:

- **(a)** as a precondition to supporting Maliki (Shiite) as Prime Minister in the new government, the KRG extracted assurances that disagreements over oil and gas matters would be resolved in 2011;
- **(b)** and the interests of the GOI and the KRG may be more aligned with the GOI needing more export to fund its budget, in particular as export increases in the south may be in a chokehold due to infrastructure bottlenecks.

Exports from the Kurdish Region of Iraq resumed in February 2011, and importantly two payments have been made to the KRG, despite former Oil Minister Sharistani's continued anti-PSC position. The tougher issue is still unresolved however: namely, the GOI validating the PSCs in the Kurdish region of Iraq.

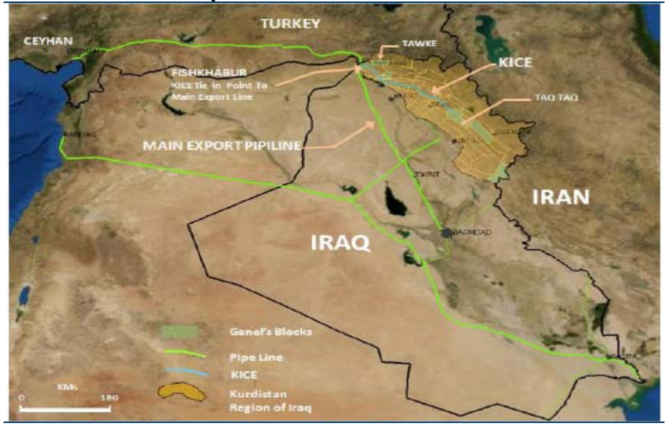
Recently, the Iraqi Prime Minister Maliki and his KRG counterpart Salih, stated that they are looking to resolve issues by the end of the year by adopting a new oil law (amending a 2007 hydrocarbons law as agreed by all political factions) or accepting that dating from February 2007. This is important not just related to the Kurdish region of Iraq, but equally for Iraq as a whole, as continued failure to create a widely accepted framework for the development of Iraq's resources risks derailing Iraq's ability to executive a national energy strategy. But it is debatable whether in such a short period of time a new law can be passed given the deeply rooted philosophical differences over the twin issues.

Infrastructure Bottlenecks Are Also Significant

When thinking of exports from Iraq/the Kurdish region of Iraq, we think it is important to understand the entire infrastructure in place, the conditions of the existing infrastructure and planned expansions across the country.

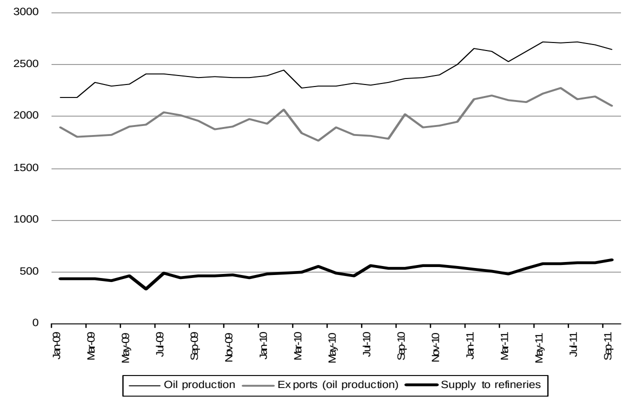
Iraq has three main export routes: **(a)** the northern distribution system via Turkey (Kirkuk-Ceyhan) with a nameplate capacity of 1.6mbd (operable currently estimated at ~800kbd with flows of c450kbd in 2011; i.e., spare capacity for KRG production with plans for debottlenecks), **(b)** the southern distribution system (Basra Oil Terminal/Khor al-Amaya) with a nameplate capacity of 3.45mbd (operable closer to 1.8-1.9mbd), and **(c)** the Kirkuk-Banias (Syria) pipeline (not operational) with a nameplate capacity of 700kbd. All of the export routes operate below nameplate capacity as infrastructure restrictions do not allow for full operation. The Kirkuk-Banias pipeline is inoperable for structural and political reasons.

Exhibit 208: **Transportation Infrastructure**



Source: Genel Energy.

Exhibit 209: **Iraqi Production (kbd)**



Source: Iraqi Ministry of Oil.

There are plans to expand pipeline capacity significantly to cope with Iraq's planned production growth from the TSCs signed to date with numerous IOCs. But the lack of a coherent political framework in Iraq and the absence of effective decision making by the administration hamper the development efforts signed with the IOCs. These institutional voids are delaying the development of critical infrastructure. We first discuss existing routes followed by the expansion projects:

350 kbd of space capacity in the Northern Line via Turkey, assuming capacity of 800 kbd vs nameplate at 1.6MBD

- **Kirkuk-Ceyhan pipeline**: the pipeline has a nameplate capacity of 1.6mbd, but the operable capacity is estimated at ~800kbd (there is uncertainty at what level the pipeline can at this stage operate). The pipeline requires repairs to the pumping stations (IT-2 south of the northern city of Mosul) to return to fuller capacity, while also the extent of corrosion is not known. Plans are in place to increase the operable capacity to 1mbd by 2013 (we assume 2015) and eventually to the full nameplate capacity of 1.6mbd, which is not our base case in this decade.

  Given the prospectivity of the Kurdish region of Iraq, there is a need for further export capacity longer term beyond the 1.6mbd from the Kirkuk-Ceyhan pipeline. For example, Al-Janabi, head of the parliament's oil and gas committee, called for the expansion of pipeline export capacity through Turkey to 2mbd. At the recent Kurdistan-Iraq conference, KRG Oil Minister Hawrami stated that the KRG has a target of 1mbd of exports via the Kirkuk-Ceyhan pipeline by 2015, which we think is unrealistic; we estimate closer to c500kbd by 2015 (ex Kirkuk).

  In the first nine months of 2011, exports from the north have averaged c460kbd from a total production of c730kbd, leaving current spare capacity at c350kbd. A large portion of production from the north comes from the Kirkuk field, which is in structural decline. In view of Kirkuk's declining production profile, this should leave enough spare capacity for production from the Taq Taq, Tawke and Shaikan over the medium term. In addition to the existing pipeline, with larger IOCs entering the Kurdish region of Iraq, there is a possibility of further infrastructure spending, particularly in view of the possible export bottlenecks in the longer term.

Hitting bottlenecks already in the South with 1.5MBD of operable capacity to the Basra Oil Terminal and 300kbd to Khor al-Amaya

- **Basra Oil Terminal (BOT)/Khor al-Amaya (KAA):** the largest export facilities in Iraq through the BOT and KAA offshore terminals are located in the south. The combined nameplate capacity of the two is 3.45mbd via two 48-inch subsea pipelines to BOT (1.5-1.6mbd operable) and three pipelines from Fao to KAA (300kbd). A network of pipelines, storage and pumping facilities transport the oil to offshore tanker loading facilities. However, the real capacity is estimated to be closer to 1.8-1.9mbd. In other words, current production would suggest bottlenecks in the southern export routes already. There are ministry plans in place to increase the capacity at BOT through three phases to 4.5mbd by 2013. However, we think this is unlikely, with delays already visible with Phase I.

- **Kirkuk-Banias Pipeline**: the pipeline has a nameplate capacity of 700kbd and is connected to the domestic reversible Strategic Pipeline and stretches into Syria. The pipeline is damaged from the 2003 war and requires repairs to pumping stations to make it operational. However, for political reasons, we expect this line to remain offline.

The reversible Strategic Pipeline allows flows from North to South and vice versa—it needs significant repair

There is also the Strategic Pipeline with a nameplate capacity of 800kbd, which is a reversible domestic pipeline. The reversible nature of this pipeline means that Iraq has the option to pump Kirkuk crude southwards for export via BOT/KAA, or to pump Rumaila crude northwards for export via Ceyhan or to refineries around Baghdad. Owing to deterioration to two of the main pumping stations and the pipeline itself, it appears that the pipeline currently is barely operable. One of the main pumping stations is currently under repair, but this limits the ability to transfer crude between the southern and northern export routes; much to the benefit of players in the Kurdish region of Iraq, as it would otherwise reduce the current spare capacity in the Kirkuk-Ceyhan pipeline if crude were to flow northwards.

Proposed Pipelines Excluding Southern Expansion

There are many new pipeline proposals, many of which look less likely. We focus here on a three-phase plan outlined by the Ministry in 2010 to expand major pipelines:

- **Phase 1 Basra-Haditha Pipeline:** this pipeline project would mirror the Strategic Pipeline, adding 1.75mbd of capacity. It would split in two, with one line going towards Syria and the other tying into the Kirkuk-Ceyhan pipeline. The completion of this project is targeted for 2013 (we have not factored this in).
- **Phase 2 Heavy Oil Project Pipeline:** this project is currently in the planning stages, so we view it as very uncertain. The expected capacity is 1.5mbd and it would run from Basra to just north of Baghdad and possibly extend to Syria. The project includes a gas pipeline, LPG pipeline and oil depots and completion is targeted for 2014.
- **Phase 3 Products Pipeline:** this project is also still in the planning stages, thus very uncertain. The Ministry proposes to build an export pipeline from the existing and the four proposed refinery projects. The location for this project is not yet known. The refinery projects (discussed in more detail later) are Karbala, Kirkuk, Nassiryah and Maysan. Tendering for these projects is expected for 2012, with project completion estimated for 2017/18. While there are likely incentives for investors for these refinery projects, we believe the key challenge is to attract partners to help fund these projects.

Generally speaking, delays in the political decision making process are creating a major obstacle for oil companies in Iraq (i.e., approval for equipment and securing the required number of rigs). In addition, Iraq closely monitors the reimbursable capex of oil companies.

Southern Distribution System and Expansion Plans

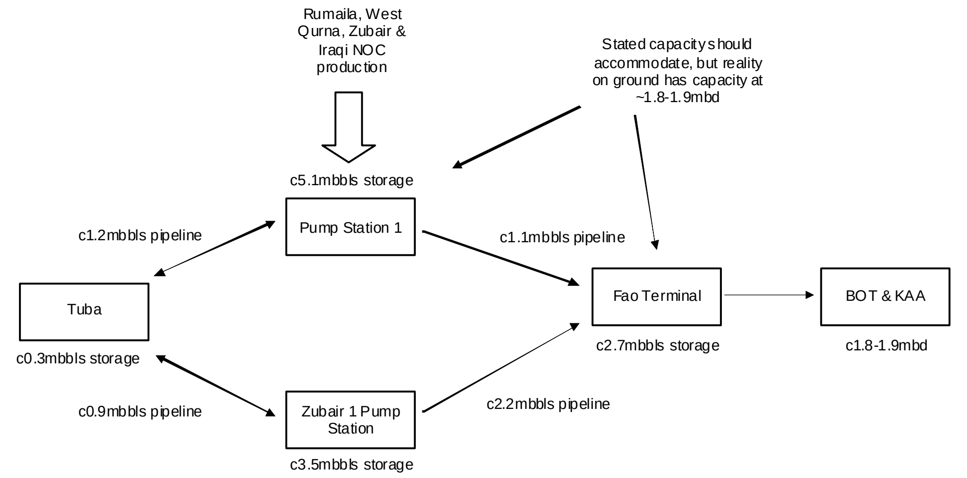
We think logistical constraints in the southern distribution system are likely to cap export increases in the near term, in particular in view of the delays to the expansion plans. For example, the first two single point moorings (SPM) planned at BOT have faced delays centred on the timely completion of infrastructure, including the underwater pipelines. Additionally, both the BOT and KAA have faced operational problems.

Pipelines to the main export terminal in the South are a decade past their expected operational life; it is important to deliver BOT improvements

According to a report from Foster Wheeler in 2007 on behalf of the US Army Corps of Engineers, the company assessed the integrity of export pipelines for the Ministry of Oil, particularly those in the southern distribution system. The report stated that the pipelines connecting to the BOT are over a decade past their shelf life (excessive corrosion) and at risk of failing at any time. These pipelines, built in the 1970s, have a 20-year life span without major inspections/upgrades.

There are plans to increase the operating capacity at BOT to 4.5mbd by 2013/14 via three phases, and the Ministry of Oil has said that these plants will be delivered on time. However, this seems unlikely, in our view, particularly as contracts for Phase III have yet to be awarded. The first phase (by Leighton Offshore) would add amongst other things two new 800kbd SPMs planned for 1Q12 with the second phase (by Saipem) adding an additional 800kbd SPM planned for 3-4Q13. Phase three would install the fourth SPM in order to take the BOT's total capacity up to 4.5mbd by 2013/14.

Exhibit 210: Southern Gathering and Export Infrastructure—Current Bottlenecks

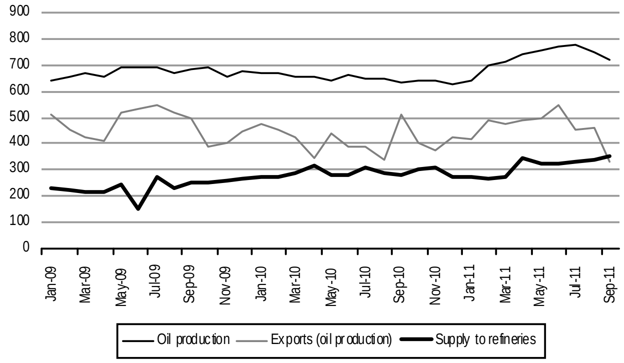


Source: Credit Suisse research.

Even if these projects were delivered on time, there are other issues that need consideration relevant to production; namely, constraints in the onshore gathering infrastructure and limited tank capacity. There are two key facilities: namely, the Zubair-1 (ZB-1) storage and pumping facility and Pumping Station 1 (PS-1). The PS-1 collects all the current production from Rumaila, West Qurna, and Zubair.

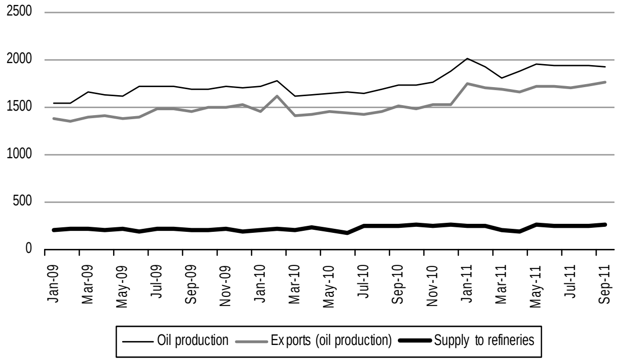
ZB-1, linked to the Fao Terminal via pipelines, has three turbine pumps, each with a design capacity of 1mbd and storage capacity of c3.5mbbls. According to WoodMackenzie, prior to 2003, only two of the pumps were in service and four of the 20 storage tanks not operational. While the stated capacity should cope with current production, industry institutions suggest that the system is already operating beyond capacity and at times had to shut in as much as 100-200kbd of production. This indicates to us that the real capacity is much lower.

Exhibit 211: Northern Distribution System



Source: Iraqi Ministry of Oil.

Exhibit 212: Southern Distribution System

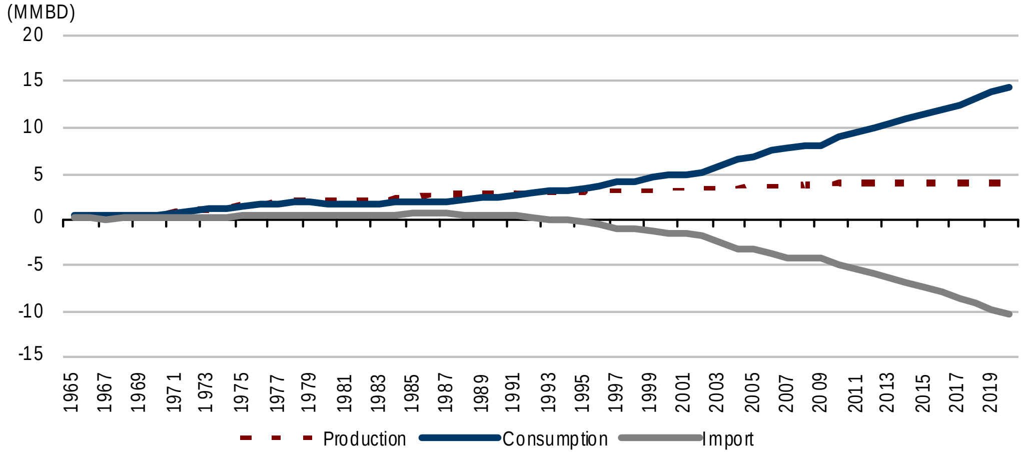


Source: Iraqi Ministry of Oil.

Another issue related to the production ramp-up in the south is a lack of water availability for reinjection to maintain reservoir pressure. Access to river water is limited, thus infrastructure is needed to gain access to the sea. This is crucial (similar to the biggest field in the world, the Ghawar, which requires substantial water reinjection) for production, in particular for the West Qurna-1 project with XOM heading the project.

Asia Pac in 2012, Stay with the Upstream

Exhibit 213: **China—Oil Production, Consumption, and Imports**



Source: BP Statistics, Credit Suisse estimates.

We prefer COSL and CNOOC in China, avoiding ongoing refining losses at the majors

Another year upon us. In APAC, energy security becomes yet more important, with external M&A and exploration in the South China Sea as recurring themes for our stock universe. With crude forecast to stay above US$100/bbl, we prefer COSL and CNOOC in China, avoiding ongoing refining losses. In Australia we prefer Woodside, ready to book 20%+ production growth in 2012, along with Origin as it prepares to sanction a 2 train LNG project. In Japan Inpex and Japex, both have growth catalysts not yet reflected in the price.

Woodside and Origin preferred in Australia, Inpex in Japan

Key themes include M&A and South China Sea exploration/politics

- **APAC theme 1: Asian M&A steps up another gear:** The imperative for APAC countries to increase international oil and gas assets continues. We expect Asia to focus on Canadian assets in 2012, among others.
- **APAC theme 2: South China Sea focus intensifies:** 2012 will see a significant increase in deepwater exploratory activity in the un-disputed deepwater South China Sea province, with CNOOC, COSL, Chevron, BP, BG & Anadarko involved.
- **China—COSL & CNOOC:** with a Brent crude forecast of US$105/bbl we expect Chinese refiners to continue to record losses, and prefer CNOOC and COSL—both exposed to the South China Sea theme.
- **Australia—Woodside & Origin:** Woodside is set to record 20%+ production growth in 2012 (Pluto I ramp up) & Origin set to sanction its 2 train LNG project.
- **Japan—Inpex & Japex:** Inpex will sanction the Ichthys LNG project and potentially move its 2nd LNG project (Abadi) forward (toward FEED) in 2012. Japex is a vicarious beneficiary as an Inpex stock holder but also has its own Canadian oil sands project sanction.

Key APAC Themes for 2012

Asian Oil and Gas M&A Spree Set to Continue

“Now this is not the end. It is not even the beginning of the end. But it is, perhaps, the end of the beginning.” Sir Winston Churchill, November 1942.

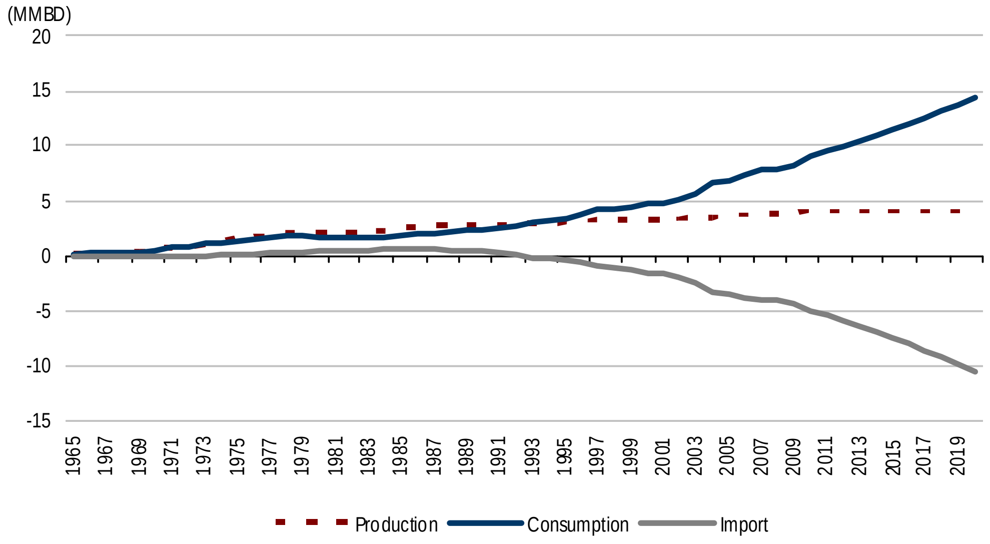
Energy security remains a key political imperative and will drive exploration and M&A

Energy security moves ever more front and center in Asia evidenced by political posturing at the recent APAC conference. While Japan and Korea's demand growth has waned, its dependence of foreign sourced oil and gas continues. The change is China, and to a lesser degree India, where consumption growth continues (driving global demand growth) but domestic supply fails to respond. As a result, the key Asian economies are increasingly competing for global oil and gas resources, both at the asset and corporate level. 'Winning' (securing the resource) is often a national definition rather than a commercial one, and to that end China appears set to dominate the regional competition. The real winners are likely resource sellers—and we think Canada could be a key focus geography in 2012 as it seeks to diversify export points away from its southern neighbor. In terms of Asian M&A activity we would suggest, using Churchill's eloquence, that this is just the 'end of the beginning' phase.

China imports could account for 10% of global oil production by 2020

China—set to import 1 produced barrel in 10 by 2020: If oil consumption growth continues at circa 500,000 barrels per day (b/d) and indigenous oil production remains at around 4 million b/d (as deepwater off-shore production gains offset onshore production maturation) then China will be importing 10 million b/d by 2020, around 10% of global oil production at that time. We understand China's informal target is for a 25% 'equity oil' coverage, i.e., that Chinese interests control or are at least invested in oil production equal to 25% of that import requirement.

Exhibit 214: **China—Oil Production, Consumption, and Imports**



Source: BP Statistics, Credit Suisse estimates.

China Inc.—strong mercantile model: Unlike the US, which appears to leave the question of energy security to market forces, China has a strong and integrated approach to sourcing international resources with three scale State-Owned Entities (SoEs) focused on international acquisitions, both at the asset and occasionally company level (Sinopec parent bought Addax Petroleum in 2009), supported at the political level with China making loans, building infrastructure, supplying military hardware, and even supporting host countries in global organizations (like the UN).

Exhibit 215: List of Acquisitions by the Chinese Oils over the Past 2 years

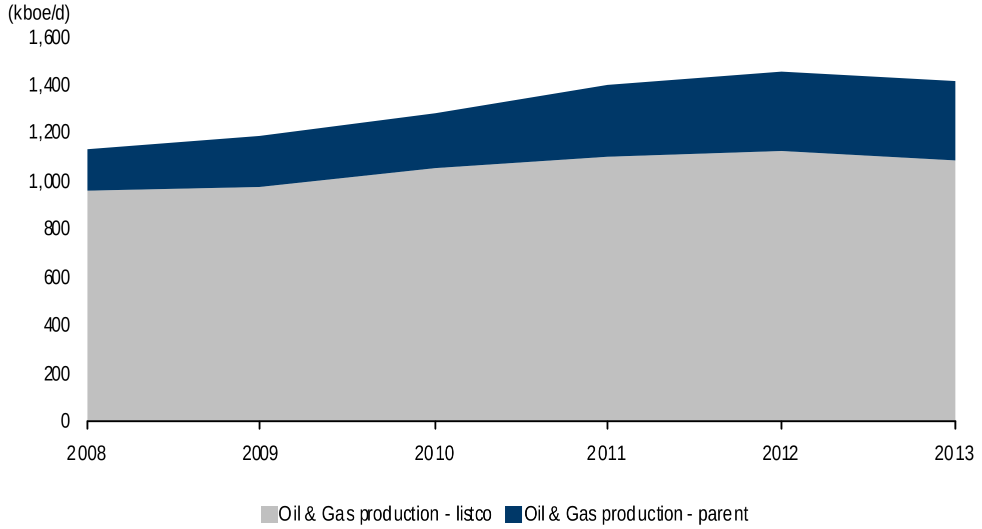
Date	Company	Country	Seller	Assets	Stake	Consideration *(US$ mn)*
March 2010	CNOOC	Argentina	Bridas	Pan American Energy	30%	3,100
October 2010	CNOOC	US	Chesapeake	Eagle Ford, southern Texas	33.3%	1,100
January 2011	CNOOC	US	Chesapeake	Denver-Julesburg and Powder River Basins, northeast Colorado and southeast Wyoming	33.3%	570
April 2011	Sinopec Group	Australia	AP LNG	20 years of LNG supply	-	n.a.
July 2011	CNOOC	Canada	OPTI Canada	OPTI Canada	100%	2,100
July 2011	PetroChina	UK	Ineos	Refineries – Grangemouth (Scotland) & Lavera (France)	50%	1,000
October 2011	Sinopec Group	Canada	Daylight Energy	Daylight Energy	100%	2,100
October 2011	Sinopec Group	Indonesia	Chevron	Rapak, Ganal, and Makassar Strait blocks in East Kalimantan, Indonesia	18%	680
November 2011	Sinopec Group	Portugal	Galp Energia	Galp Brazil Services	30%	3,540
November 2011	Sinopec Group	Cameroon	Royal Dutch Shell	Acquired an 80% stake of Pecten Cameroon from Royal Dutch Shell	80%	538

Source: Reuters, Bloomberg, company data, Credit Suisse estimates.

CNOOC's strong net cash position suggests M&A will continue, but internal exploration is also a priority

Chinese SoEs have slightly different drivers: CNOOC is compelled to acquire international assets at the listed entity, and therefore has always stated that it seeks value in the transactions it targets/completes. The company has previously prioritized deepwater assets to build competence to support its focus on the domestic South China Sea deepwater strategy (for example buying into Total's Akpo project in Nigeria in 2006), but recently had moved toward nearer dated production assets like its stake in Bridas in Argentina as its shallow domestic production matures. Given the very strong net cash position, we expect CNOOC will continue to seek and bid for both near-dated production assets and longer-term development plays going forward. For Sinopec, international exploration/long dated assets are purchased at the parent level and incubated with the intention of future injection into the listed entity. The parent has been very active lately, taking two significant stakes in Brazil (Repsol and Galp) and a further stake Origins LNG development in Australia as well as Canada (with a recent corporate acquisition—Daylight Energy). Sinopec appear focused on long-dated upstream opportunities in 'hot' addresses but have shown an inclination thus far to move to build a global downstream footprint. PetroChina has shown restraint in the global race for oil and gas resources thus far despite a quoted US$40 billion M&A budget, with the deal with Shell to acquire unconventional gas play Arrow Energy, Athabasca oil sands in Canada and Ineos refining capacity in Europe (Scotland and France). PetroChina also participates in 2 Technical Services Agreements (TSAs) in Iraq (Rumaila and Halfaya)—bringing Enhanced Oil Recovery (EOR) expertise.

Exhibit 216: **Sinopec Group (Listco + Parent)—Segmented Upstream Oil and Gas Production 2008–2013E**



Source: Woodmac, company data, Credit Suisse estimates.

CNOOC also focuses in domestic deepwater exploration/production: With Chairman Fu stepping down from CNOOC, new Chairman Wang has stressed the importance of domestic exploration & production in his internal speech. In the first results briefing he attended, he has emphasized deepwater exploration/production as one of the core development strategy in the next 5 years.

Target to Drill 2-3 Deepwater Wells in South China Sea in 2012

Apart from its involvement through PSC partners in Offshore China, CNOOC's own participation in deepwater exploration starts in 2011, initially targeting to drill its first deepwater well in 2H11, but now pushed back into 1H12. CNOOC is utilizing its first ultra-deepwater semi HYSY981 for South China Sea exploration in the next 2-3 years. HYSY981 is owned by CNOOC parent and operated by COSL. At the time of writing, HYSY981 is scheduled for delivery "in the coming weeks," i.e., at the beginning of January 2012, and CNOOC is targeting to drill 2-3 deepwater wells in 2012. As we head toward second half of 2012, we are likely to see newsflows on the drilling results, and if the first 2-3 wells are deemed successful, CNOOC will accelerate its deepwater exploration program.

Deepwater exploration in the South China Sea is becoming a focus area—more detail later in this section

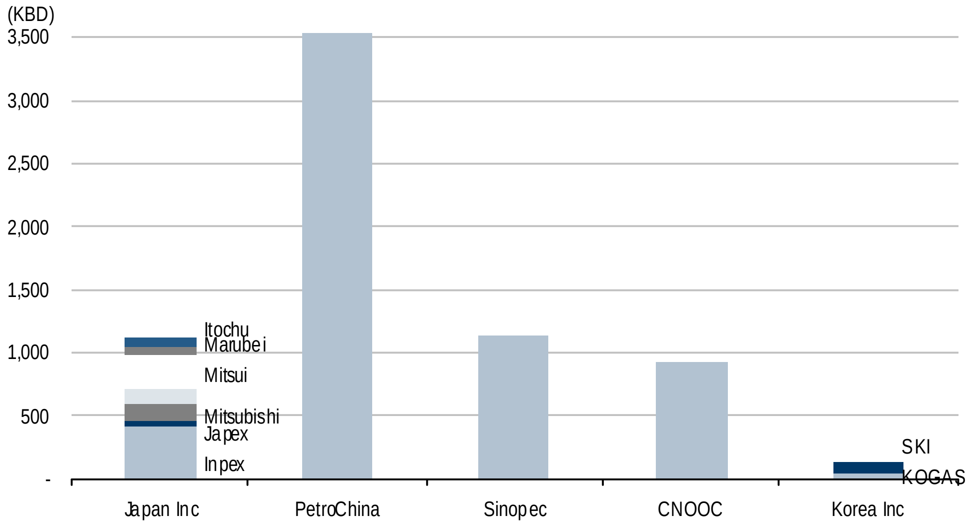
COSL and CNOOC the Winners

COSL has recently placed an order for a 4th new semi COSL Prospector that is scheduled for delivery in 2H14. While the water depth (1,500M) and rig configuration is designed to target the North Sea market, COSL indicated that the water depth level is also suitable for deepwater South China Sea. Hence, there is also a possibility that this rig can be utilized in Offshore China if CNOOC's exploration program in 2012/13 becomes successful. Before CNOOC drills its deepwater wells we are already seeing a massive pickup in COSL's seismic volumes YTD—1H11 3D seismic collection is up 72% YoY, and 1H11 geophysical segment EBIT is up 160% YoY.

Japan—Fragmented Approach to Energy Security

With scarcely any indigenous oil production Japan's oil assets are currently distributed on a fragmented basis—with Inpex producing circa 400k barrels of oil equivalent day (boe/d), Japex a further 60k boed, JX (the largest refiner in Japan) producing 130k boed with the 4 trading companies (Mitsubishi, Mitsui, Itochu and Marubeni) producing a further 520k boe/d, the challenge is that its peers/competitors for international assets in China possess greater scale, and a more cohesive "national offering" versus the Japanese, whose primary value add is potential access to low cost finance.

Exhibit 217: 2011 Oil & Gas Production—Japan vs. China vs. Korea

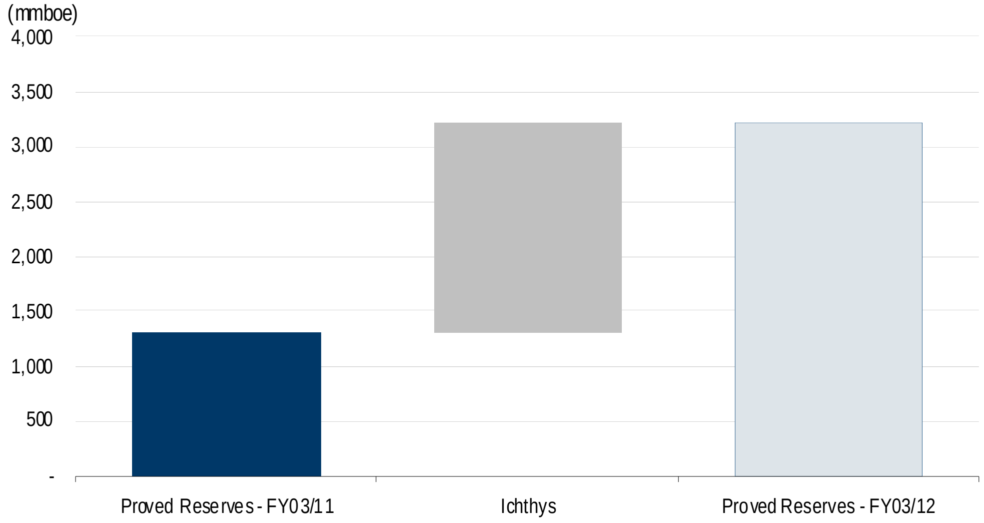


Source: Woodmac, company data, Credit Suisse estimates.

Inpex broadening it LNG net to Western Canada

Inpex: developing LNG projects to supply Japan: Inpex has been working patiently on two major LNG projects; the most advanced being the Ichthys LNG project in Western Australia which will sanction imminently and will produce 8.6 Million Tonnes pa (MTpa) from 2017, sold primarily to Japanese utilities/gas distributors. It is also starting to make progress with its second major LNG project—Abadi in Indonesia where it holds a 60% stake having recently farmed out a 30% stake to Shell. Widening its net Inpex recently farmed (bought) into Nexen shale gas resources in Canada, likely with a view to export the gas as LNG to Japan, as LNG liquefaction projects in British Colombia begin to take shape. With these projects turning toward commercial reality we view Inpex as the reserves winner in APAC in 2012.

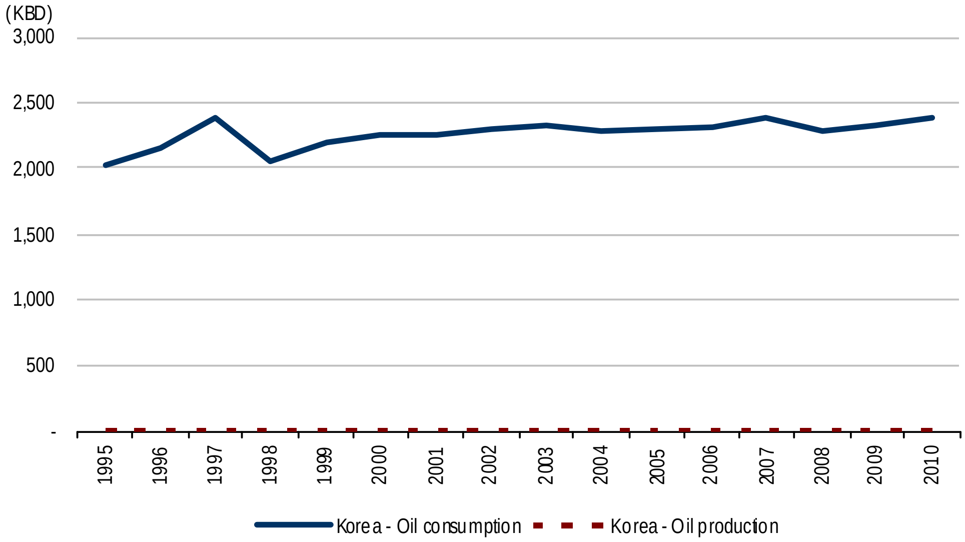
Exhibit 218: Inpex—Reserve Bookings in FY03/12



Source: Credit Suisse estimates.

Korea: reserves anxiety but Japonesque in approach: Korea like Japan has virtually no indigenous oil and gas production and therefore energy security is a very real issue. Unlike China, it depends on a mixture of government entities (KNOC and KOGAS) and Chaebols such as SK & GS Holdings. The government provides soft funding in the shape of exploration carries for both types of entity but thus far no clear national champion has emerged to lead Korea as it competes with China and Japan for global resources. KOGAS has historically taken small upstream stakes in upstream LNG projects in return for long term LNG off-take (although the transactions are generally arms length) but stepped out a few years ago taking an upstream stake in Encana Horn River/Montney shale gas resources and a stake in the yet to be sanctioned Kitimat LNG liquefaction project in British Colombia.

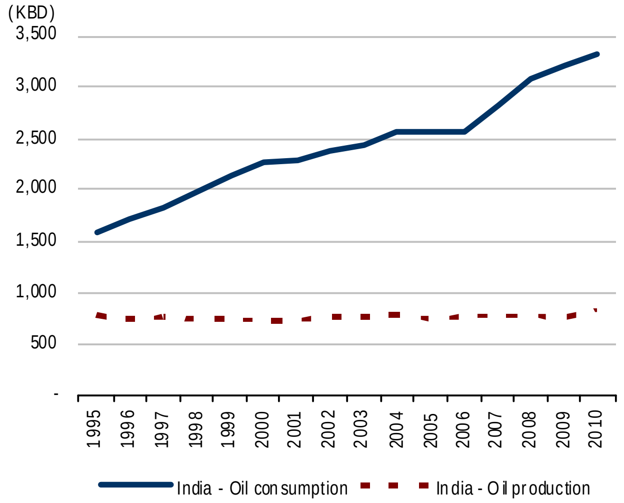
Exhibit 219: Korea—Oil Consumption vs. Production



Source: BP Statistics, Credit Suisse estimates.

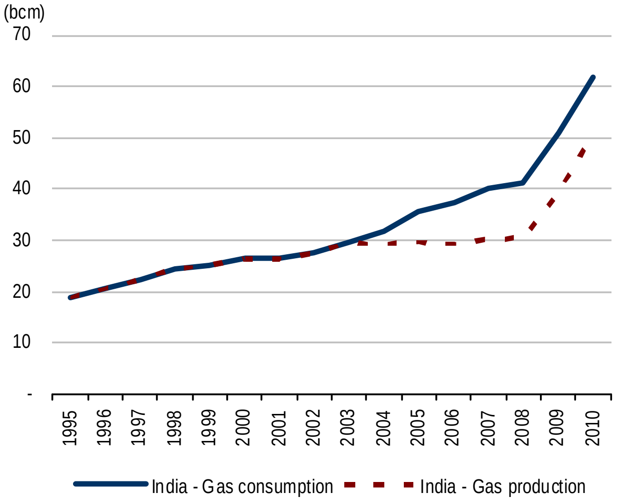
India—Reliance leading the charge: India faces a similar challenge to China, albeit on a smaller scale with a deficiency in oil and gas production vs. consumption and consumption growth outpacing indigenous production gains. India continues to lack a National champion, with Reliance Industries leading the charge thus far (with a US$13bn net cash pile) along with ONGC.

Exhibit 220: India—Oil Consumption vs. Production



Source: BP Statistics, Credit Suisse estimates.

Exhibit 221: India—Gas Consumption vs. Production

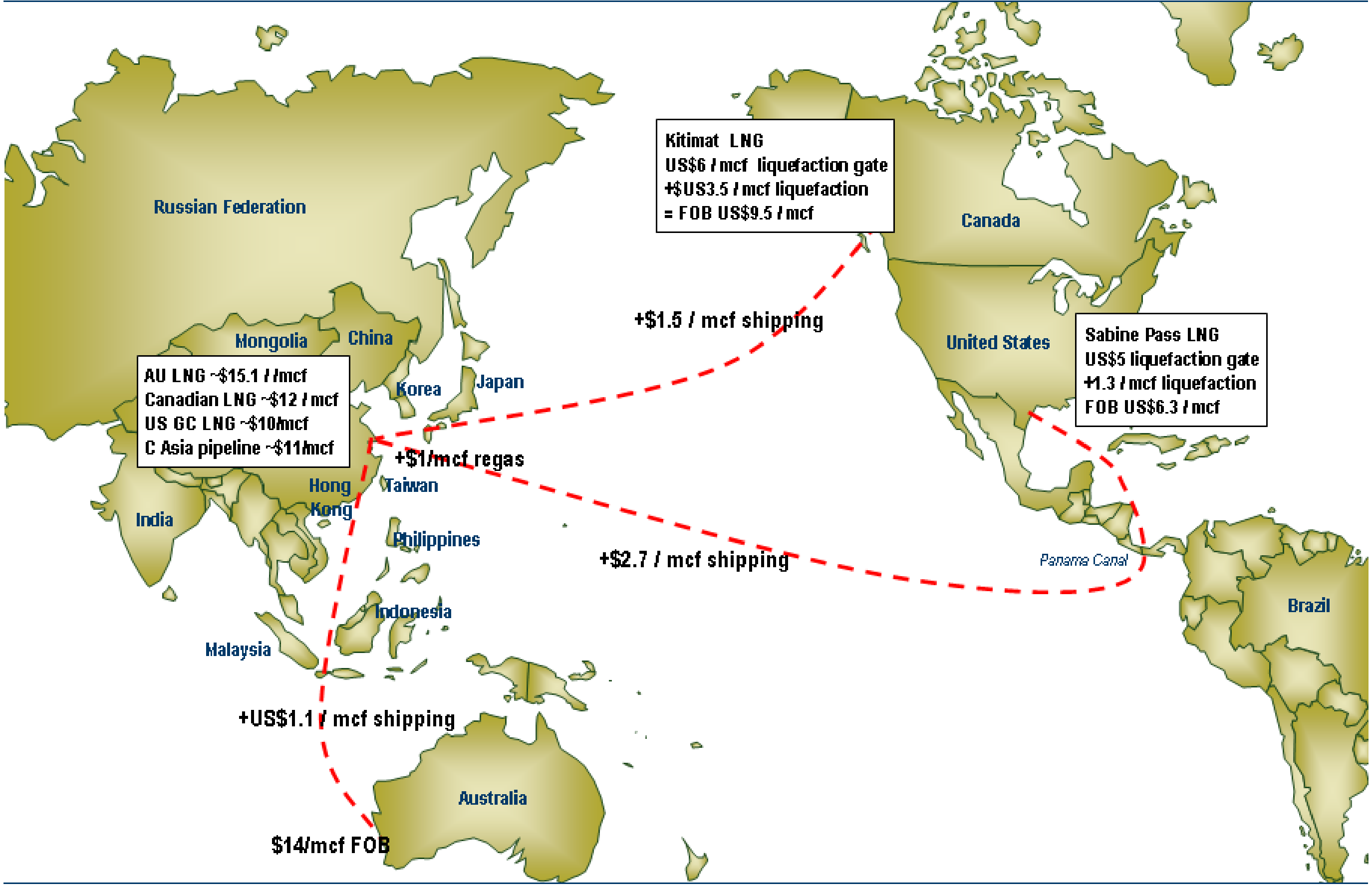


Source: BP Statistics, Credit Suisse estimates.

Australia—How much can Asia buy? Shell's failed attempt to buy the remaining stake in Woodside in 2001 is an oft-quoted reminder of the potential challenge of foreign interest in Australian assets/companies, but since this time a series of Asian based investments have occurred, primarily in the LNG space with LNG customers taking small upstream stakes at the point of committing to off-take (CNOOC into North West Shelf, Sinopec into Origin (twice), multiple Japanese transactions (Tokyo Gas, Kansai Electric into Pluto, Tokyo Gas, Osaka Gas, & Chubu Electric into Chevrons share of the gorgon project etc) and events like Malaysia's Petronas taking a stake in Santos's GLNG project. Last year Shell along with PetroChina acquired Arrow Energy, then used that entity to acquire Bow Energy in late 2011. With Shell's remaining 24.27% stake waiting for an outcome would an asset hungry Asian player look to acquire the stake and would the Australian Foreign Investment review Board approve such a deal, or even a complete Woodside takeover?

Canada: America's environmental hand wringing could be Asia's next supply point… What a difference a border makes. In the US intense political focus has zeroed in on the approval of the 1,700 kilometre Keystone XL pipeline—set to bring oil sands sourced crude to US refiners. President Obama recently delayed the decision to approve the pipeline to 2013 (i.e., post the 2012 Presidential election) leaving Canada to muse on the strategic benefit of a second outlet for its massive oil and gas resource base. With liquefaction now being proposed to send gas as LNG to Asia from Kitimat, British Colombia, and the potential to send oil sands sourced crude 2012 could bring a slew of further Asian investment in the Canadian oil space (with more than US$20bn invested already). In Canada potential targets for farm-ins or more from Asia would include Encana, Nexen, Cenovus, Connacher and Husky. Korea's Kogas has already formed a JV with Encana in parts of Encana's holdings in Horn river and Cutback Ridge and most recently Japanese player Inpex

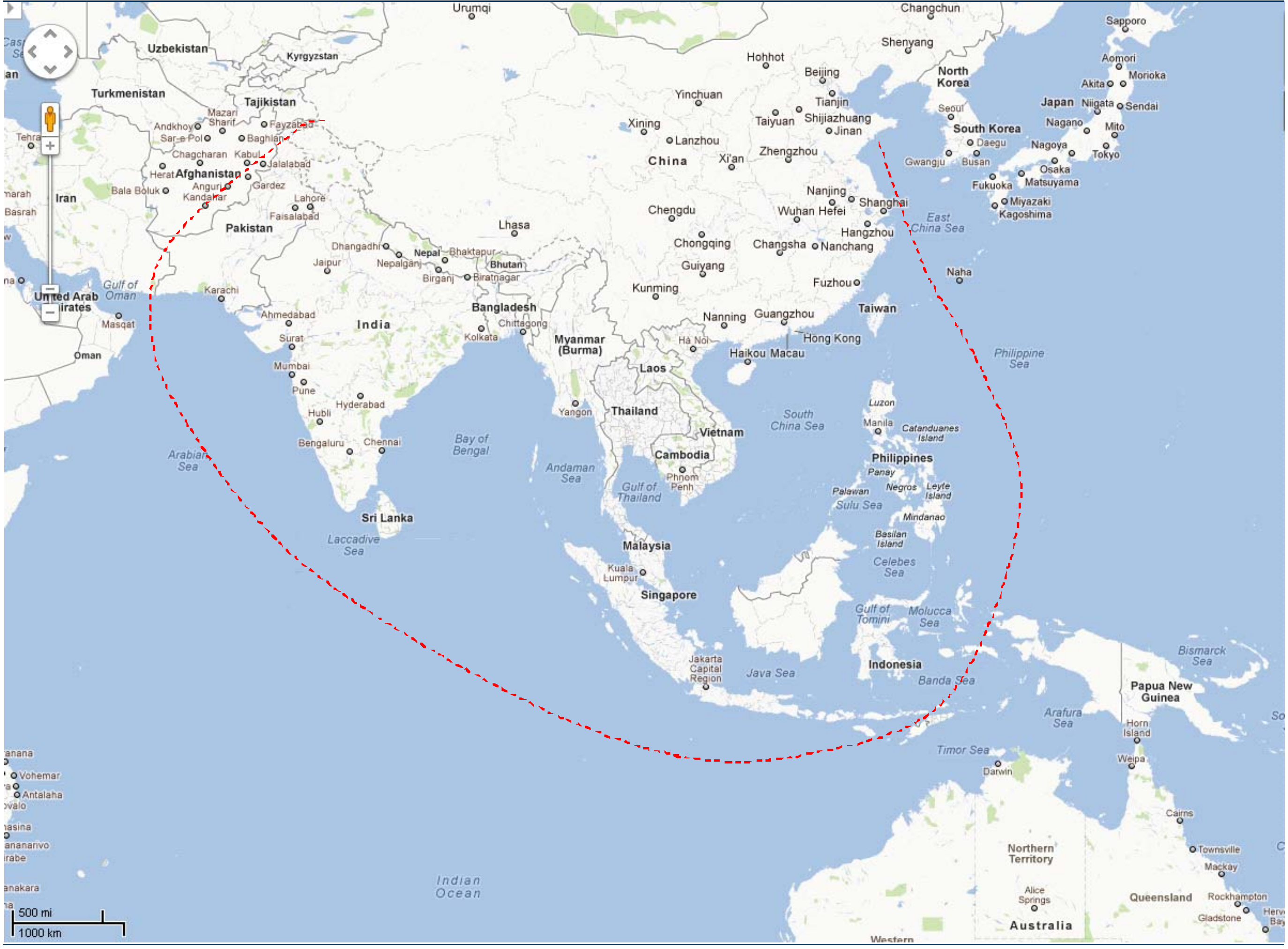
Exhibit 222: **Multiple Gas Supply Points to Shanghai—Estimated Built Up costs (Based on Credit Suisse Macro Assumptions and $100k/d LNG Tanker Rate)**



Source: Credit Suisse estimates.

South China Sea tensions mount: disputes in the South China Sea (SCS) are not new, but the escalation in rhetoric and recent public commentary by the US brings the issue back into focus again as we enter 2012. China claims the vast majority of the area using its ‘nine dotted line’ (please see map below), drawing all of its Southern neighbors plus Taiwan to dispute the claim. With an estimate of 200 billion barrels of oil and 2000Tcf of gas the stakes could be high. With the requirement to source rising crude imports going forward the imperative for China to understand and develop a new scale province in its backwater (as it were) is high. CNOOC, as the offshore champion for China, (along with its sibling service provider COSL) stand to be the main beneficiary should the quoted prospectivity come to fruition. Chevron, BP, BG and Anadarko also hold exploration acreage in the deepwater SCS and we expect further activity on those blocks in 2012.

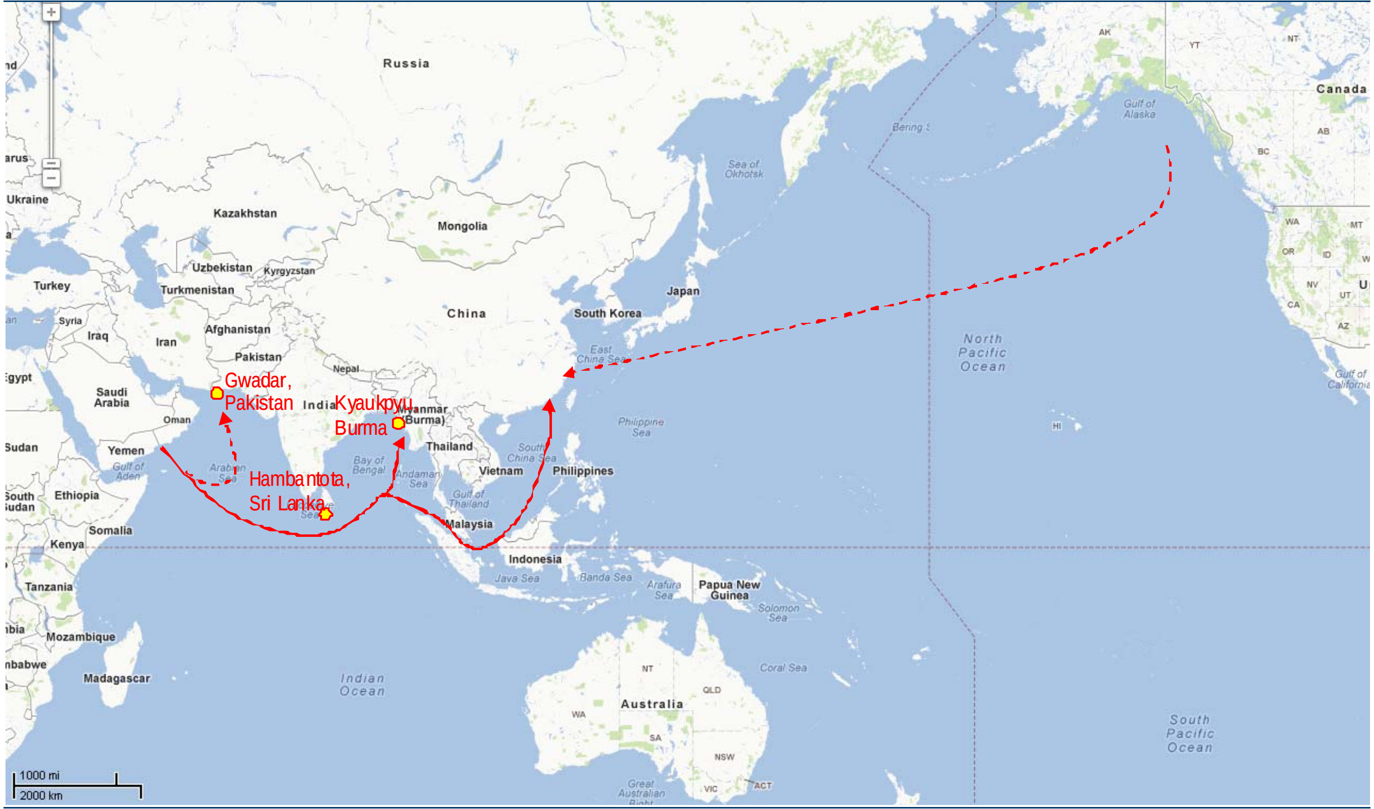
Exhibit 223: China's "Extended" South China Sea Boundary



Source: Google map, Credit Suisse research.

Straits of Malacca pinch point for Chinese crude imports: With the majority of China's oil imports set to pass through the Straits of Malacca confidence of crude delivery will be a key concern to the nations planners, very well aware that social stability could be challenged should there be a shortage of oil products as a result of the inability. This is one of the reasons that China is now focusing significant military capex into building out its naval capability. Far behind the US but rapidly expanding its nuclear submarine fleet (with one analyst estimating that China will have more nuclear submarines that the US by 2020), the ability to assure delivery of its crude imports is a very real issue for China.

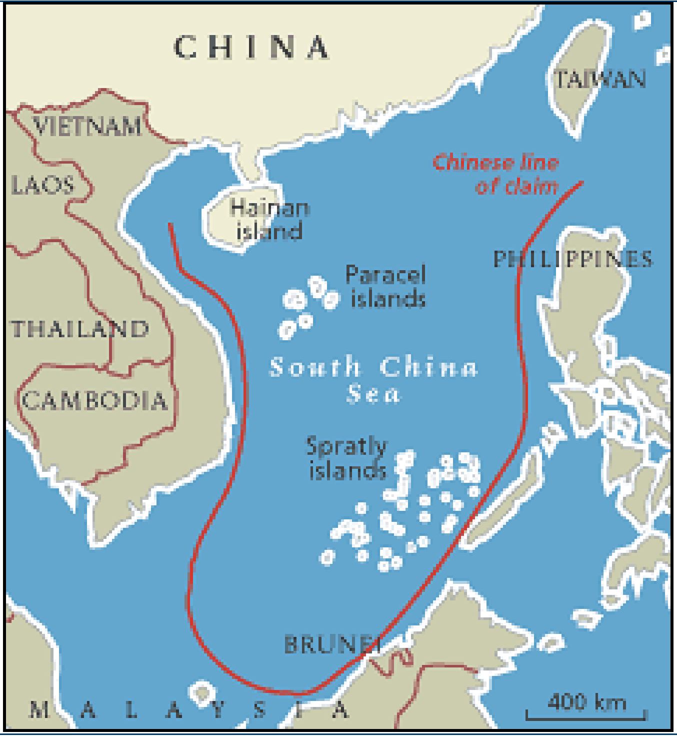
Exhibit 224: Straits of Malacca Pinch Point for Chinese CrudeImports



Source: Google map, Credit Suisse research.

'String of Pearls' mirrors earlier mercantile models: China is building out a series of 'friendly' ports around the Indian Ocean—the so-called string of pearls, in Kyaukpyu in Burma and Gwader in Western Pakistan along with Hambantota in Sri Lanka. The first two provide potential access for crude oil to China bypassing the Straits of Malacca, whereas Sri Lanka provides a staging post as China increases its navel competence and reach to provide support for the transportation of crude from Africa and the Mid East.

Exhibit 225: Map of South China Sea



Source: Credit Suisse research.

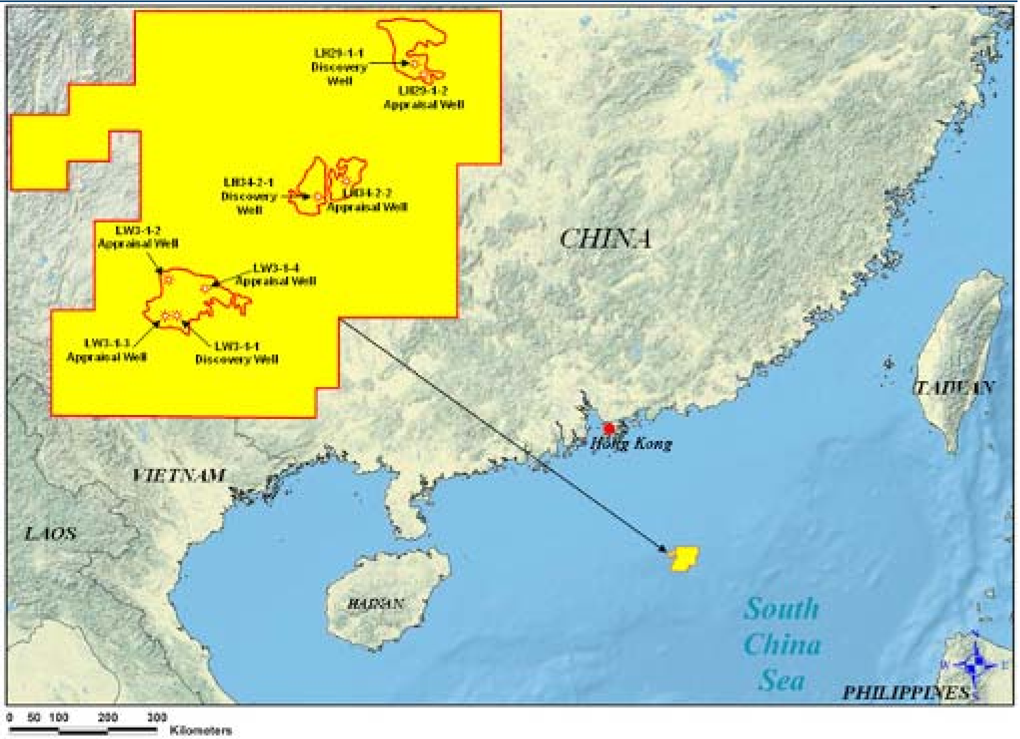
200bn boe of oil and 2000 Tcf of gas in the broader South China Sea?

South China Sea—a potential and proximal crude source: recent papers on the topic have suggested there could be as much as 200 billion barrels of oil and 2000TCF of gas in the broader South China Sea. If directionally correct, i.e., if the area is a potential world class province then the need to take marine risk from more distant supplies would be ameliorated—hence China's determined approach to the issue of rights. China claims sovereignty over the South China Sea Islands and surrounding waters, a claim opposed by the Philippines, Vietnam, Indonesia, Taiwan, Cambodia, Thailand, Singapore and Malaysia. In the current (12th) Five-Year Plan China appears to be focusing on the undisputed area of the South China Sea from a deepwater perspective. Should that area confirm the prospectivity suggested in the headline resource numbers this will increase the stakes (and therefore tension) for all of the players.

Almost 1bn boe of gas equivalent already found at Husky's Liwan project, 300km offshore Hong Kong

Husky developing the 1st Deepwater South China Sea project: Husky is the operator of Block 29/26, situated about 300 kilometres South West of Hong Kong. In 1450 meter water depth the project should sanction imminently, and with an estimated 4-6 Trillion Cubic feet (Tcf) of gas (100% basis). Husky has already taken the board decision to proceed and awaits the project Overall Development Project (ODP) approval. Husky recently announced it had signed gas sales agreements with CNOOC Parent in the US$11-13/mcf range. Project capex is estimated at US$6.5bn. the sanction of the project will be a positive first step in the development of the wider potential in the South China Sea. In the near term the approval of the ODP by the Chinese Government will allow CNOOC to book its 51% stake—which would equate to circa 400 million boe—more than 100% Reserve Replacement Ratio vs. 2011 production.

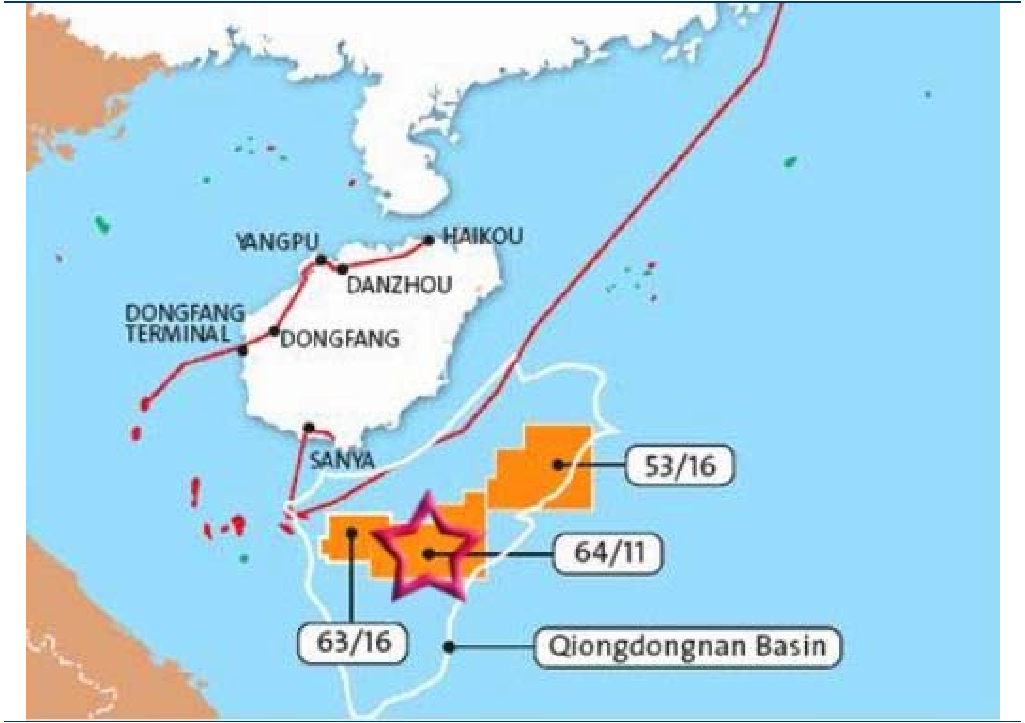
Exhibit 226: **Liwan Deepwater Gas Project in South China Sea**



Source: Husky Energy.

BG, Chevron, and Anadarko also hold deepwater SCS blocks: BG is the operator on 2 deepwater South China Sea blocks (64/11 at 1500 metres and 53/16 at 2100 metres). With an initial exploration success already announced BG will continue to explore and appraise the block through 2012. Chevron (operator)/BP acquired a deepwater block previously held by Devon in 2011, and Chevron are understood to be planning a 2 well exploratory campaign in 1H12. Anadarko also holds an exploration license for block 43/11 (1,500–3,000 meter water depth), which it was understood had been deprioritized several years ago but is again a focus for the company going into 2012.

Exhibit 227: **BG, Chevron & Anadarko Blocks in South China Sea**



Source: Credit Suisse Research.

Offshore Hainan in focus in 2012

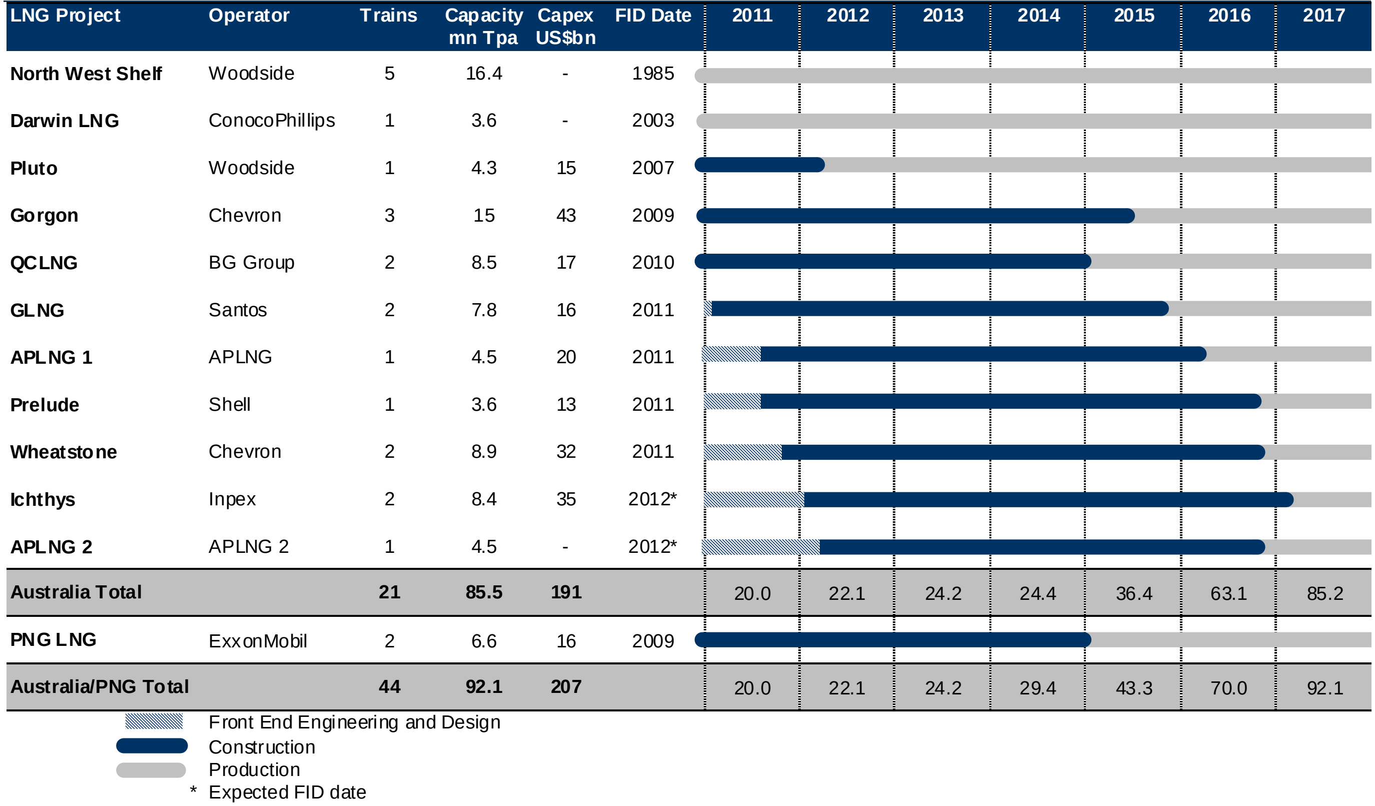
13th Five-Year plan—unlucky for some? We suspect that China plans to use the 12th Five-Year plan (2011-2015) to better understand the challenges of deepwater exploitation in the undisputed portion of the South China Sea, and its prospectivity. Should the view be taken that A) China has the competence to drill and produce in the deepwater and B) the broader South China Sea is a prospective as is hoped, then the challenge (for China's neighbours in the region, and their 'friends') will be whether China stays within the undisputed area or broadens its exploration/production activities into the disputed area.

Australian Oil and Gas in 2012

Significant project execution risks remain

Australian LNG: welcome to our reality—8 LNG projects now in construction phase: Between Australia and PNG there are 8 LNG projects under construction at present. In early 2012 the 9th LNG project—Ichthys—is expected to be sanctioned, however Pluto train 1 should move from commissioning phase to production phase by 2Q12. (Exhibit 228) summarizes the development status of each LNG project under construction. Additional trains may be added via brownfield expansion at Gorgon, Wheatstone, Pluto and PNG, which are not included below. Additional LNG trains will only increase Australian/PNG LNG output and extend the period of tight construction resource availability.

Exhibit 228: **Summary of LNG Projects in Australia and PNG Online, under Construction of Near-Term FID Expected**



LNG Project	Operator	Trains	Capacity mn Tpa	Capex US$bn	FID Date	2011	2012	2013	2014	2015	2016	2017
North West Shelf	Woodside	5	16.4	-	1985							
Darwin LNG	ConocoPhillips	1	3.6	-	2003							
Pluto	Woodside	1	4.3	15	2007							
Gorgon	Chevron	3	15	43	2009							
QCLNG	BG Group	2	8.5	17	2010							
GLNG	Santos	2	7.8	16	2011							
APLNG 1	APLNG	1	4.5	20	2011							
Prelude	Shell	1	3.6	13	2011							
Wheatstone	Chevron	2	8.9	32	2011							
Ichthys	Inpex	2	8.4	35	2012*							
APLNG 2	APLNG 2	1	4.5	-	2012*							
Australia Total		**21**	**85.5**	**191**		20.0	22.1	24.2	24.4	36.4	63.1	85.2
PNG LNG	ExxonMobil	2	6.6	16	2009							
Australia/PNG Total		**44**	**92.1**	**207**		20.0	22.1	24.2	29.4	43.3	70.0	92.1

▨ Front End Engineering and Design
▬ Construction
▬ Production
* Expected FID date

Source: Company data, Credit Suisse estimates.

Over $190bn to be invested over next 5 years—can it be done? We see significant project execution risks ahead as the individual projects compete for skilled and semi skilled workers. Companies are mitigating their Australian workforce and AUD exposure by completing as much construction as possible offshore. Examples of this include modular development of LNG processing units in Asia by Pluto and Shell developing Prelude using Floating LNG technology.

Is contingency enough? Despite careful preplanning and Front End Engineering and Design (FEED) work, unexpected surprises emerge as these projects move from the planning to the construction phase. Most projects factor in 10-15% contingency in their numbers, but we have already seen both Pluto and PNG LNG projects incur unexpected costs, causing the total budgets to be increased. We remain cautious over fixed price lump sum turn key contracts such as the STO:AU-led GLNG project. Contractors will wear some cost increases but will typically find ways to pass on a portion of the unexpected cost increases.

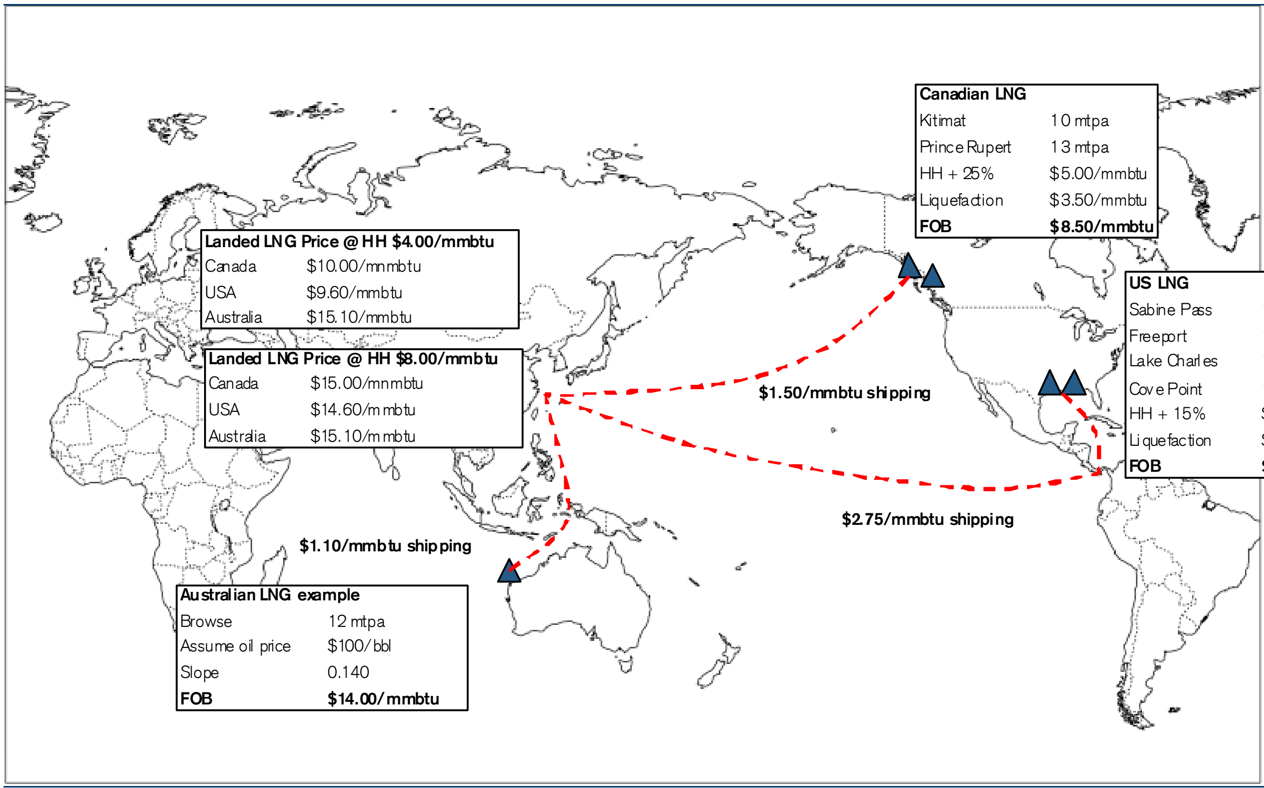
Funding spotlight on OSH and STO

The funding crunch—cost blowouts could put pressure on some smaller LNG players. OSH:AU recently announced the XOM-led PNG LNG project budget had increased from $15.0bn to $15.7bn. OSH:AU has some spare funding capacity, thanks to a combination of sustained oil production and high oil prices, but if costs increase over US$17bn we expect the company will need further equity. STO:AU undertook a minimum equity raising prior to reaching FID for its GLNG project, and on the surface could be vulnerable to a cost increase or delay in start-up. The company recently sold some non-core assets, commenced a dividend reinvestment plan and has benefited from higher oil prices, however a large cost blowout at GLNG (and to a lesser degrees PNG LNG) could put funding pressure on STO:AU further down the track.

Lower cost East African and US LNG exports threatening unsanctioned LNG projects in Australia

Pace of future LNG approvals expected to slowdown due to higher costs, lower quality, and emerging threat from North America and East Africa. After spending the past couple of years being a front-runner for LNG supply, Unsanctioned green field LNG projects (e.g. Browse, Arrow LNG, Scarborough) will struggle to reach FID in the next few years. In addition to the high cost environment, these projects suffer from issues such as remote location, JV misalignment on preferred development concept and gas resource quality. They also now face an emerging threat from North American and possibly East African LNG, with early sales from the US being very cost competitive compared with Australian LNG. Exhibit 229compares the landing cost of LNG into Asia from Australia, Canada and the USA.

Exhibit 229: Competitiveness of Australian LNG vs. North American LNG into Asia at $4 and $8 HH Price and $100 Oil Price



Canadian LNG	
Kitimat	10 mtpa
Prince Rupert	13 mtpa
HH + 25%	$5.00/mmbtu
Liquefaction	$3.50/mmbtu
FOB	**$8.50/mmbtu**

Landed LNG Price @ HH $4.00/mmbtu	
Canada	$10.00/mmbtu
USA	$9.60/mmbtu
Australia	$15.10/mmbtu

Landed LNG Price @ HH $8.00/mmbtu	
Canada	$15.00/mmbtu
USA	$14.60/mmbtu
Australia	$15.10/mmbtu

US LNG	
Sabine Pass	16 mtpa
Freeport	12 mtpa
Lake Charles	14 mtpa
Cove Point	14 mtpa
HH + 15%	$4.60/mmbtu
Liquefaction	$2.25/mmbtu
FOB	**$6.85/mmbtu**

Australian LNG example	
Browse	12 mtpa
Assume oil price	$100/bbl
Slope	0.140
FOB	**$14.00/mmbtu**

Source: Company data, Credit Suisse estimates.

Environmental debate continues to dog the Coal Seam Gas sector. The CSG sector in Australia has had to combat a sustained negative publicity campaign from various environmental groups and media personalities in 2011. The industry has been guilty of being on the back foot in educating the general population over CSG, and in particular addressing the publics concerns over water production and treatment, potential impact on aquifers, salt disposal, land access, landowner compensation, and fracking. The companies involved in the CSG industry have started to fight back with scientific information, but it will take considerable time to turn public opinion around. The situation is worst in New South Wales, where STO:AU and AGL Energy have CSG operations, with the government imposing a moratorium on all fracking and new CSG licenses until it completes its own investigations. We expect the situation to calm down slightly in 2012 and don’t expect it to slow down the 3 sanctioned CSG to LNG projects, but it may make it harder for Arrow Energy (owned by Shell and PetroChina) to complete environmental assessment on its own 2 train 8 mtpa LNG project by the end of 2013.

Testing for liquid rich shales in Australia in 2012

Shale/unconventional gas story gaining traction in Australia. In 2011 we saw an exponential increase in interest in Australian shale gas potential. A number of deals we consummated with Majors buying into various shale plays. We now see BG taking a direct interest in the Cooper Basin shale, COP and Mitsubishi in the Canning Basin and HES in the South Georgina Basin. Very little delineation of the shale potential has occurred, with the only real drilling and frac test being completed by Beach Energy in the Cooper Basin. We expect to see a substantial increase in shale drilling in 2012. Key questions investors want answered include: Are there any liquids rich shales in Australia? If so, who has them and what are the technical properties? Can drilling and frac service costs be brought down to a level where dry shale gas can be economically produced?

Further refining capacity likely to be removed. CTX:AU is reviewing its refinery business, which is likely to result in the closure of one or both of its two Australian refineries. CVX owns 50% of CTX:AU and has been assisting the company in the review process, which is expected to be completed by mid-2012. We expect CTX:AU will move to close both refineries in a phased manner, with the critical hurdle being the security of gasoline supply to meet Australian specifications. Following Shell’s decision in early 2011 to close the Clyde refinery, a decision to close the Kurnell refinery would leave Sydney as being one of the largest cities in the world with no refinery capacity.

More M&A on the way? Aussie oils underperformed against the oil price in 2011, thanks to concerns over project execution (OSH: AU and STO:AU) and future growth potential (WPL:AU). If underperformance continues throughout 2012 we expect some M&A chatter to return to these names, especially as projects are derisked through the construction phase. Among smaller caps we expect there to be further M&A activity among some of the smaller shale/unconventional gas names as work continues to delineate and derisk these resource plays.

Latin America: YPF Gaining

Production shortfalls remain in focus at PBR; YPF could benefit as shale potential is proven

Within Latin America, we think the *Transition* theme will be evident in 2012, although in two opposite ways: (1) the Brazilian Energy sector is transitioning from a phase of exploration euphoria to development reality for the Pre-salt, and we think this will be illustrated by a production profile from Petrobras that will fail to provide strong oil growth until 2013-2014 at the earliest; (2) the Argentina Energy sector is transitioning to a deregulation phase, and we are also on a possible new exploration period, with YPF's recent one billion bbls Vaca Muerta shale discovery being a tangible evidence of the country's renewed resource potential.

Theme 1: Petrobras Low Oil Production Growth

More challenges and less oil growth is what we believe is happening with Petrobras. From higher natural depletion, increased watercuts, lack of enough oilfield services capacity for maintenance and growth, and a tougher ANP, a number of factors, in our view, are contributing to production that is consistently coming short of expectations. Deep-diving in PBR's production profile lead us to conclude that there will only be an inflection point in production growth on 2013-2014 at best. With 2011 being a weak year for capacity additions, and 2012 additions being back-end loaded, we can only expect for a step change in 2013, if all goes well. With usual delays to platform start-up and production ramp-ups that are taking close to two years, we believe 2014-2015 is a more realistic timeframe for investors willing to play the production growth theme.

The Problems

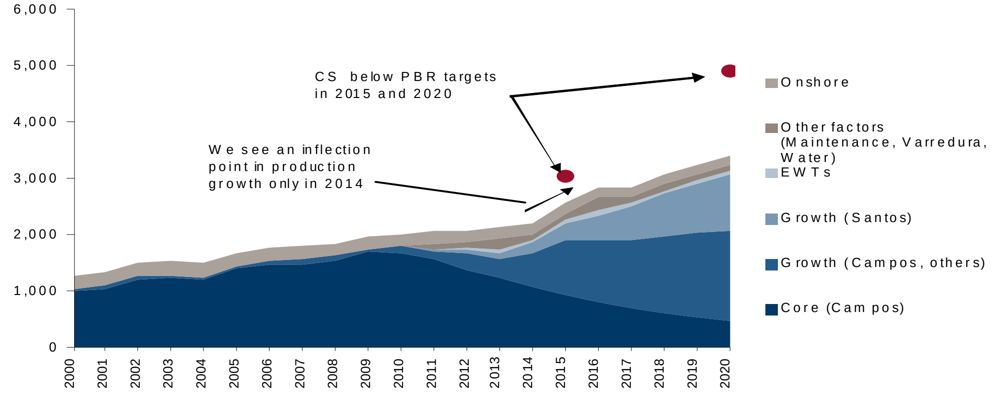
We believe it is valid to raise the question of why PBR's production is failing to perform as expected: historical five-year targets have been 13% too high, and PBR has not achieved a 2011 guidance that was set in July. Our analysis points to three main reasons: (1) observed decline rates in the Campos basin of 13-16%, (2) the supply chain is stretched on a number of fronts, notably increasing Pre-salt drilling rig demand means that less is left for new and tie-back wells in Campos, (3) more maintenance and tougher ANP are also impacting c.3% of production. We think all these factors persist going forward.

The Consequences

There are a number of investment case implications to a more conservative production profile for Petrobras, be it due to geological/reservoir reasons, supply chain reasons, or regulatory reasons. In our view, two of the most important consequences are: (1) production targets that continue to be too aggressive, implying in underlying results that may disappoint consensus earnings estimates, and (2) the need for PBR to add more capacity to get the same delta in production as in the past.

Exhibit 230: Petrobras Domestic Oil Production and CS Forecasts (kbd)—Inflection Point around 2014

PBR production inflection point is 2014



Source: Petrobras, Credit Suisse estimates.

Theme 2: Argentinean Shale Can Get Bigger

Significant resource potential in Argentine liquid rich shales

One billion barrels is big, and it can get bigger. This can be significant for YPF shares that have been reflecting Argentina macro concerns and failing to capture any value for unconventional resources. Back in May, YPF announced a 150mmboe unconventional resource estimate for the northern part of Loma La Lata. In November, the company increased that number significantly to 927mmboe, of which 741mmbbls are oil. And there is more: two additional wells drilled outside Loma La Lata allowed YPF to expand the potential production area by another 306km2, almost doubling the 428km2 where the 927mmboe are located. We continue to play the 'micro' investment case in YPF (price improvements, shale), believing there is relatively low probability of the dividend being at risk on the macro level.

Valuing YPF Shale Resources

Valuing shale resources on a $/bbl basis is valid, as the usual $/acreage metrics do not illustrate well the upside when resource numbers are going up. We take Eagle Ford and the Bakken as the two most comparable basins in the U.S. (Exhibit 231).

Exhibit 231: Comparison between Vaca Muerta Formation and Similar Basins in the US

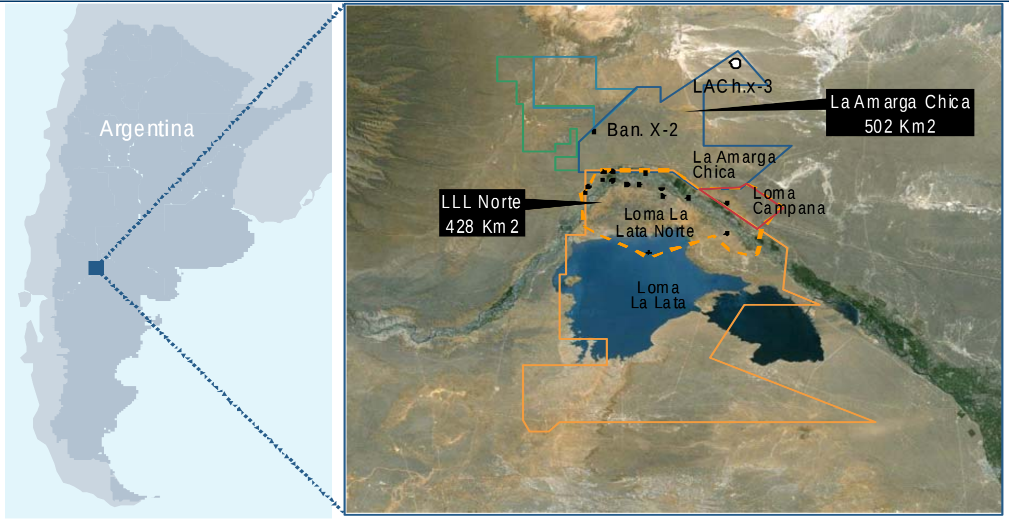
Basin	Thickness (m)	Oil quality (API)	Vertical initial production per well (bpd)
Eagle ford	55	40.0	25
Bakken	30	40.8	50
Vaca Muerta	**250**	**41.8**	**333**

Source: Credit Suisse estimates based on charts from YPF's Society of Petroleum Engineers.

We will come back with a detailed shale exercise in another analysis. For now we try to incorporate uncertainties about Argentina shale economics by taking a 50% discount to our U.S E&P team average estimate of Eagle Ford—Bakken $8.4/bbl. We get to $4.2/bbl, which is similar to around $5/bbl for resources drilled with high-costs wells that compare to YPF's $7.0m/well estimate. We also keep in mind that fiscal terms in the Bakken are not too dissimilar than in Argentina: 18% royalties plus 11% tax on revenues vs Argentina's 12% royalties, 35% corporate tax rate, and 1-2% provincial sales tax. Oil in the Bakken is exported via rail, whereas in Loma La Lata, midstream infrastructure is in place. Overall, oil price remains a key difference due to Argentinean regulation. Thus the $4.2/bbl on 741mmbbls gets us at $3.1bn or $7.9/ YPF ADR, without including any value for the La

Amarga Chica acreage. We could also get to further $1.9/ADR assuming a $10,000/acre value on La Amarga Chica's 306km^2 net to YPF

Exhibit 232: YPF Shale Acreage—Loma La Lata, Loma Campana, and La Amarga Chica



Source: Credit Suisse research based on YPF data.

Global Gas (ex-US) in 2012—Tight Markets Favor BG, RDS, and Total

BG, RDS and Total are the main beneficiaries of a tightening LNG market through 2015

There is no such thing as a truly global gas market today, and this is not expected to change for at least a decade. The main transmission mechanism of pricing between the various gas consuming basins (Europe, Asia, North America) is Liquefied Natural Gas (LNG): the problem is that there is not enough liquefaction capacity (at least not enough spot LNG) to smooth out pricing differentials between basins.

Global gas markets should become more integrated going forward, as the share of LNG within global gas consumption rises from 9% in 2010 to 14% in 2020. However, there will still be significant pricing differentials and therefore cargo arbitrage opportunities between basins during the 2011-15 period. In the medium term, we continue to see the world as split between three major gas markets with very different dynamics: a self-contained and oversupplied gas market in North America, a hybrid market in Europe where oil indexation is expected to stay under pressure, and a fast-growing Asian market reliant on LNG imports.

We see several themes for international gas markets in 2012:

(1) Global LNG market tightening, especially in Asia-Pacific;

(2) LNG projects sanctioning: winners and losers; and

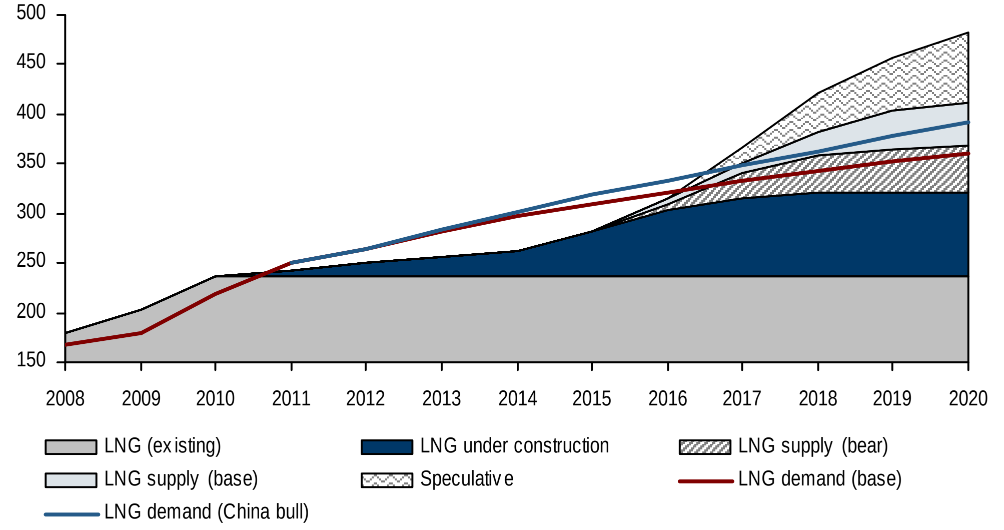
(3) In Europe, weak gas demand puts pressure on oil indexation.

1. Global LNG Market Tightens Further in 2012

2011 review: The global LNG glut seen in 2009-10 created by the US shale gas revolution, the Great Recession and the Qatari LNG ramp-up has disappeared quickly after the Fukushima nuclear crisis, leaving a more balanced gas market in 2011. The mothballing of nuclear capacity post-Fukushima created c.9mtpa of incremental LNG demand in Japan in 2011, and contributed greatly to the tightening of the LNG market in 2011. Qatar has provided the lion's share of incremental demand in Asia, having both uncontracted available capacity and the willingness to do so. Spot LNG prices in North-East Asia rose to $17/mcf in 2011, reflecting a tighter market and also rising oil-linked LNG prices.

Looking into 2012 and 2013, we believe the global LNG market will get tighter, and will continue to do until 2016. **Most of this tightness will be concentrated in the Asia-Pacific region rather than Europe**. The main driver of this tightening is a lack of new liquefaction additions against a backdrop of continued LNG demand growth. In 2012, we see only 7.3mtpa of capacity additions in 2012 from Pluto Train 1 and Angola LNG, a marked slowdown in liquefaction capacity growth compared to the 26mtpa of annual LNG additions in 2009-11 (mostly from Qatar).

Exhibit 233: **Global LNG Demand vs. Potential Supply (in mpta)**



Source: Company data, Credit Suisse estimates.

NB: China bull demand case assumes that 30% of additional gas demand is met by LNG.

On the demand side, we expect continued demand LNG growth from the non-OECD, especially in Asia, and to a lesser extent from Europe.

- **Asia** should make up the bulk of LNG demand growth in the medium term. In **Japan**, we expect further LNG demand as nuclear reactors are still being shut down, months after the Fukushima accident. Currently, LNG fired power is the primary replacement for nuclear power that has been lost. The anticipated start up of new nuclear plants from 2013 in Japan will cap LNG demand growth thereafter. The other traditional buyers in East Asia (Korea and Taiwan) should show trend demand growth.
- Demand in **China** and **India** should grow fast from a much smaller base, and their impact on global LNG demand should be larger than the Japan-Korea-Taiwan.
- Meanwhile, new markets in the Southeast Asia should open up with the completion of regasification terminals, such as Thailand (2011), Singapore (2013-14), and potentially traditional LNG exporters Indonesia (2012) and Malaysia (2012-13).
- **Europe** should see a material rise in LNG demand in the medium to long term as domestic gas production declines and buyers seek alternatives to high-priced Russian gas. In the near term, however, the trick will be to attract cargoes away from higher-priced markets like Asia, which is expected to be short LNG until 2017. For now, Qatar has continued to provide LNG into North-West Europe despite significantly lower prices than in Asia. This might change in 2012-13 as Asia will be come more short LNG, and once Qatar successfully signs long-term supply contracts in Asia at crude price parity (i.e. it will no longer has an incentive to restrict supplies into Asia-Pacific). With little incremental Atlantic Basin LNG plant in 2012-14 and attractive LNG diversion opportunities to Asia, we think European LNG import growth could be more muted than in recent years, particularly given a weak economic outlook.
- New LNG markets in **Latin America** and the **Middle East** should continue to grow. These markets made up just 4% of global LNG demand in 2010, but are already changing trade patterns as demand in these regions is counter-seasonal relative to the northern Hemisphere (MidEast demand is higher in the summer for air conditioning). Kuwait and Dubai started import LNG in 2009 and 2010. Other MidEast countries

which could join the club of LNG importers in the medium term include Bahrain, Jordan and Israel. In Latin America, we expect Argentina to import growing volumes of LNG in 2012 after already doubling imports in 2011, as domestic gas demand soars and indigenous production lags.

Implications for Gas Prices

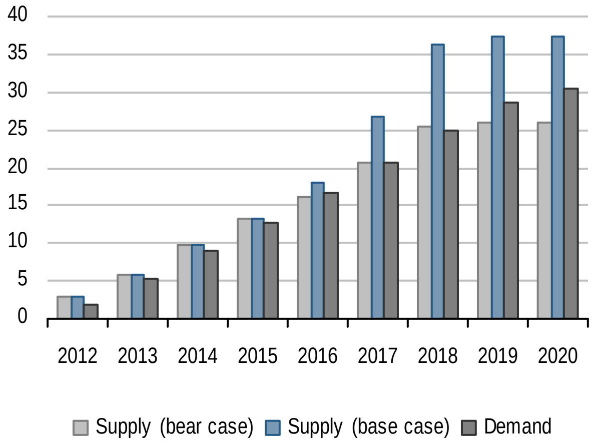
We expect sustained spot prices gap between Asia-Pacific and European markets. In a tight gas market, we expect spot gas prices to remain in a range of $12-16/mmbtu in the Asia-Pacific region for the next 3-4 years. We would expect a pricing gap to be persistent between European and Asia-Pacific markets for several reasons, including transportation, cost differentials and inter-fuel switching opportunities in European power generation.

Asian LNG Price Premium to Prevail

Using a bottom up Asian LNG demand and supply model, we conclude that **near-term demand strength will continue to support highly correlated LNG/crude oil prices**. Asia usually runs with little or no near-term uncontracted LNG demand, but a combination of the Fukushima incident plus under-contracting in Korea has led to a material five-year supply gap. Pulling together the demand and supply, our analysis suggests that Asia will be short of LNG supply until 2017.

Exhibit 234: **Atlantic Basin LNG Balance: Better Supplied**

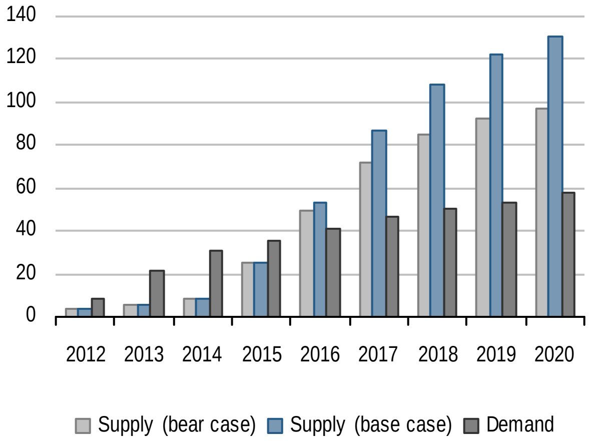
LNG supply vs demand growth vs 2011E base in mtpa



Source: BP Statistical Review, Credit Suisse estimates.

Exhibit 235: **Pacific Basin LNG Balance: Famine, then Feast**

LNG supply vs demand growth vs 2011E base



Source: BP Statistical Review, Credit Suisse estimates.

Qatar stands (almost) alone in its ability to meet the majority of Asia's near-term shortfall, given its speculative ramp up of LNG supply in the last 24 months. Looking at uncontracted supply, considering all Australian projects (existing, de-bottlenecking, projects in FEED and speculative), all of the proposed projects in North America (both the US and Canada) and Qatar production that could be redirected from other markets, it is clear that Qatar has a near-monopoly on uncontracted supply until 2015. This will have a crucial bearing on contract prices in Asia, as Qatar looks to reimplement its preferred approach, which is Crude Price Parity.

Near-term demand window 20-30mtpa to 2014, even after Qatar: If all of the firm uncontracted supply (in reality Qatar) is directed to Asia, this still leaves a 20-30mtpa shortfall in 2012-14 as the market waits for supply to catch up. There are three primary ways to meet this shortfall:

Upward Quantity Tolerance (UQT). Existing LNG contracts typically have a 10% UQT clause where buyers can request additional cargoes supplied under the contract price if sellers have the reasonable capacity to meet the request. We estimate this could provide around 10mtpa if fully exercised.

Spot cargoes from other LNG basins. LNG portfolio players such as BG will be able to provide LNG to Asia from their global portfolios. In terms of new LNG start-ups in the 2012-14 period, cargoes initially destined for the European or US market should be diverted to Asia, e.g., we could imagine that some flexible volumes from Angola LNG and Algeria (Skikda, Arzew) could go to Asia rather than Europe or the US (their original destination).

Further redirections from Qatar above and beyond the 9mtpa used in our base case.

The need to call in LNG from outside the region augurs well for spot and short-term pricing in Asia, as sellers reflect the regional supply deficit in spot pricing.

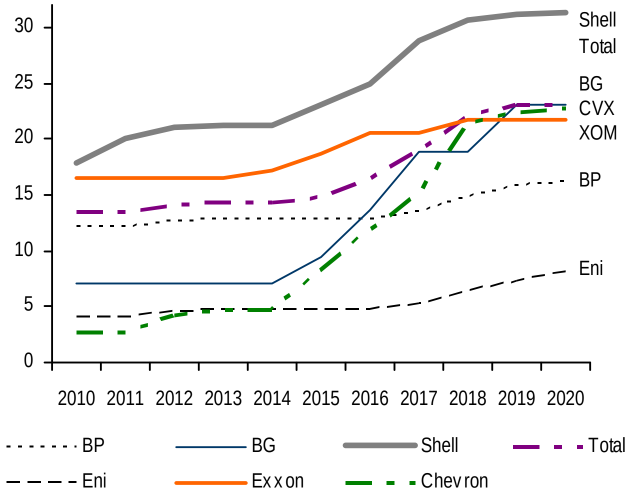
Asia LNG price forecast: Given the supply-demand strength and using CS' Brent crude forecast of US$105/bbl in 2012, we forecast an average landed (Delivered ex Ship—DES) price of US$15.3/mmbtu in Japan. This reflects a 75% correlation to JCC (Japan Crude Cocktail) and an average shipping cost of US$1/mmbtu.

We assume new contracts/existing contract price reviews will gradually lift price correlations through to the middle of the decade. The major driver will be Qatar, looking to convert its short term supply to long-term contracts, seeking ever increasing price correlation toward Crude Price Parity.

Who Benefits from Cargo Diversion Opportunities to Pacific Basin?

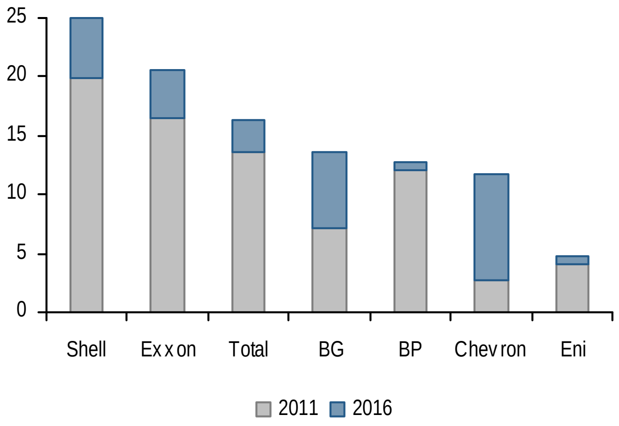
While Qatar should be the main beneficiary of this pricing strength in Asia, other companies with access to flexible LNG volumes should also benefit. In particular, we see BG and Shell as well-positioned to benefit from a tighter LNG market in the 2011-16 period, and also from the next wave of LNG supply additions this decade.

Exhibit 236: **Global Majors LNG Capacity, 2010-20E**
in mtpa of equity LNG capacity



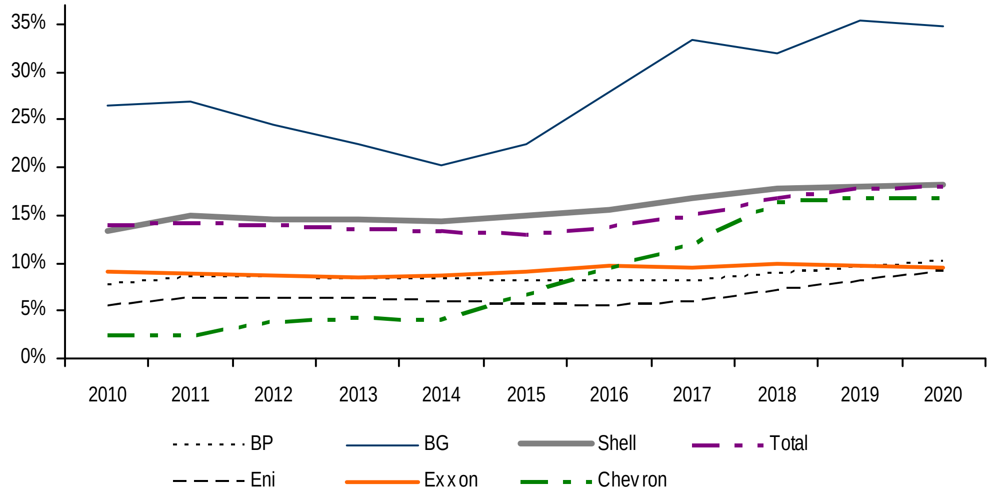
Source: Company data, Credit Suisse estimates. NB: Downstream LNG exposure.

Exhibit 237: **Global Majors LNG Capacity, 2011 vs. 2016E**
in mtpa of equity LNG capacity



Source: Company data, Credit Suisse estimates. NB: Downstream LNG exposure.

Exhibit 238: **LNG Gas as a % of Total Upstream Production**
in %



Source: Company data, Credit Suisse estimates. NB: Upstream LNG exposure.

- **BG** is well-placed to benefit from tightening in the LNG market, as it is the only true LNG "portfolio" player among the majors. It has significant flexible LNG volumes (e.g., from Equatorial Guinea, Egypt and Nigeria) and strong trading capabilities allowing it to benefit from arbitrage opportunities. The LNG division is set to make up just under 30% of BG's EBIT in 2011. In terms of future LNG growth, BG is building the two-train QCLNG plant in Queensland (which is now 25% complete, and 6 months ahead of the next CBM-to-LNG project, Santos' Gladstone LNG) and is looking to sanction a third train by the middle of 2012 (although we think an FID in late 2012 or 2013 is more likely). It is also well placed to source LNG from lower-cost countries, through i) a proposed LNG export scheme in Tanzania with Ophir, ii) its recent ground-breaking agreement to purchase LNG from Cheniere's Sabine Pass terminal at Henry Hub linked prices, iii) its proposed LNG export project at Lake Charles.

- **Shell** is the largest LNG producer among majors and is set to maintain its leadership throughout this decade. Shell should be able to benefit from a tighter market given its position in Sakhalin II and Malaysia LNG (contracted), and flexible volumes from Qatargas 4. Its Integrated Gas division (largely LNG) represents 24% of 2011 post-tax earnings, the highest ever proportion. LNG is also a large part of Shell's future production growth, with 8.3mtpa of LNG under construction (Gorgon, Prelude and Pluto) and a large portfolio of potential LNG options (Arrow, Sunrise, Browse, Abadi, BC LNG). Shell sanctioned Prelude FLNG, the world's first Floating LNG project, in May 2011. We think its Floating LNG technology could help Shell gain access to other gas resource opportunities at advantageous prices. We see its entry into Abadi (Indonesia) with Inpex as an example of this strategy, with other moves likely to follow.

2. LNG Project Sanctioning Outlook

While there is a growing shortage of LNG to meet 2012-15 demand, there are plenty of LNG projects competing to fill demand in the 2017-20 period. Recent gas discoveries (e.g. in East Africa) and technological advances (e.g. shale gas, CBM, Floating LNG) have spawned many proposed LNG projects which could meet late decade demand, even with a more bullish scenario for China LNG demand.

In our global gas model, we are tracking 90 liquefaction projects worldwide, of which 33 LNG plants currently onstream, 11 plants under construction, 15 plants in the engineering phase ("possible") and 31 projects under study ("speculative"). From 2011 to 2020, we forecast a 173mtpa increase in global liquefaction capacity, of which 75mpta are already under construction and 97mtpa from "possible" unsanctioned projects. In addition, we have identified a further 88mtpa of "speculative" projects, which we do not include in our supply Base Case. This compares to our forecast of a 110mtpa increase in LNG demand between 2011 and 2020.

Given our below-consensus long-term LNG demand scenario, the world will need fewer LNG plants by 2020 than are currently proposed. If all "speculative" LNG projects went ahead, the global gas market would become severely oversupplied, with a potential surplus of 122mpta LNG by 2020. We expect the vast majority of these "speculative" projects to be cancelled or delayed for several years.

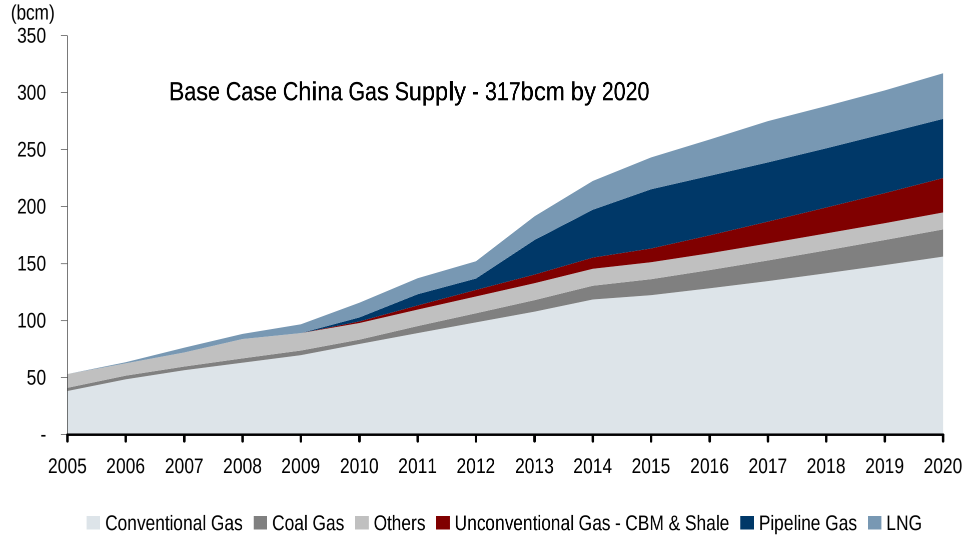
Pricing Will Be an Issue—Asia Won't Take LNG at Any Price

Cost competition among unsanctioned LNG projects will become more important

We are concerned that affordability, particularly in China and India, will limit gas market growth. We also believe that countries like China will find alternative sources of gas supply in the long term (e.g., unconventional domestic gas, pipeline imports from Central Asia).

At our forecast regional LNG contract prices, China is an extremely marginal buyer at this point: In our recently published global gas report, "*From tight to loose by 2016*" (22 November 2011), we highlighted that China has already secured enough gas to meet its realistic gas consumption needs to 2015 with a combination of domestic conventional gas production growth plus contracted LNG and pipeline gas imports. The 12th five-year plan appears focused around Chinese state-owned Entities (SOE's) high-grading activity around domestic unconventional gas exploitation, to ramp up production in the 2016-20 window. The degree to which China believes it can ramp up unconventional production will alleviate the need to commit to further scale LNG purchases at current LNG contract prices (85% correlation to crude). We assume that China accepts all of the contracts committed to date, and will make limited further deals in the next five years, but we do not subscribe to the view that China is a massive LNG demand source in the near/mid-term given prevailing regional LNG prices.

Exhibit 239: **Credit Suisse: Base Case China Segmented Gas Supply 2005–2020E**



Source: NBS, China OGP, CEIC, Credit Suisse estimates.

We believe China and India, which do not have a history of paying high prices for LNG, will resist signing traditional long-term oil-indexed contracts—even in a post-Fukushima world—given i) potential for domestic production, and ii) improving prospects for North American and East African LNG exports, pointing to a looser market in the latter part of this decade.

Given sensitivities around pricing for newer LNG buyers, we believe **pricing will be a key consideration** in whether a project will succeed or not. The issue is that high construction costs on new projects are making it difficult for sellers to offer competitive pricing terms. Liquefaction costs have increased in recent years to c.$1,000/ton of annual capacity.

Many LNG Projects Won't Fly: There Will Be Some Losers

The implication of this view is that LNG projects will be competing with one another for the same customers. Hence, we believe cost of supply will become a more important differentiator for future yet to be sanctioned LNG proposals.

We think the best positioned LNG projects are those with the **lowest all-in capital costs**, which could due to a number of factors, including: 1) the presence of existing infrastructure, making brownfield expansions more economic, 2) low upstream production costs thanks to geological factors, 3) associated liquids content, 4) favorable fiscal terms, 5) proximity to consuming markets resulting in low transportation costs, particularly to Asia.

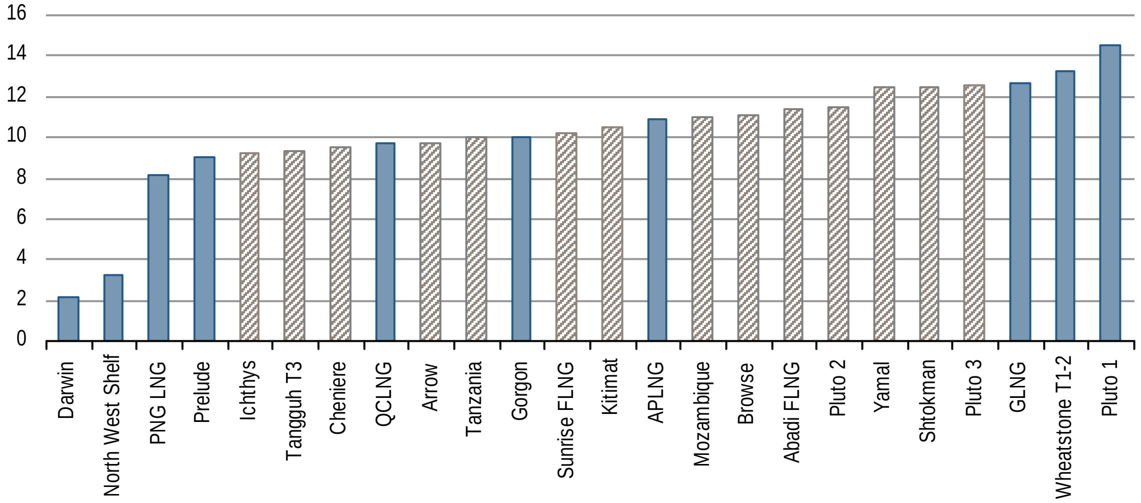
Beyond cost considerations, we think some buyers (particularly traditional buyers in East Asia) continue to value **security of supply** and will therefore retain a preference for exporting countries seen as "lower risk." Companies with only one or two LNG projects in their portfolio may find it more difficult to persuade buyers to sign long-term contracts than larger companies with diversified supply portfolios.

Offsetting possible reluctance from Japanese buyers to buy from countries seen as "higher risk," supply diversification away from LNG behemoths Qatar and Australia is an important consideration for South Korea. All things equal, we think Kogas may prefer to buy LNG from new exporters such as Canada, the US, Mozambique, or Russia rather than from Qatar and Australia.

LNG Cost Curve: Only "Advantaged Projects" Will Make It

In Exhibit 240 below, we show our estimated LNG cost curve: blue bars represent sanctioned LNG projects and striped grey bars show pre-FID projects. An important caveat is that there are still many unknown factors driving these projects' economics, most notably capex (for nearly all projects) and in some cases fiscal terms (e.g. Mozambique). Therefore, the cost curve below should be seen as indicative only. Costs at new offshore Australian hubs such as Gorgon and Wheatstone should also fall.

Exhibit 240: **LNG Projects Break-Even Prices (Striped bars = pre-FID projects)**
in $/mcf



Source: Company data, Wood MacKenzie, Credit Suisse estimates.

NB: Breakeven price defined as FOB LNG price for a 12% IRR (nominal) over full project cycle, excluding M&A premium. Cheniere assumes $5.5/mcf Henry Hub.

Winners vs. Losers: What Projects Can Be Sanctioned in 2012-13?

2011 has been a good year for LNG project sanctions, with 5 FIDs adding up to 26.8mtpa of supply: Gladstone, APLNG T1, Prelude and Wheatstone in Australia, and DS LNG in Indonesia. Many projects around the world have been proposed and are moving towards FID, but some have progressed faster than others.

Plenty of projects are competing against each other for the same end-markets and in the same 2012-13 time window; we think only those that are 100% ready will make it in this timeframe. Bringing a project to FID requires many ingredients: an LNG project needs to be fully lined up in terms of gas resources, customers, funding, political & environmental approvals, stakeholder alignment and construction/labor contracts, otherwise it is highly likely to be overtaken by other projects.

Overall, we expect to see more LNG project sanctions in the next two years adding up to >50mtpa, encouraged by high current contracted and spot LNG prices. We think projects which have a higher probability of being sanctioned in 2012 or 2013 include:

(1) **Brownfield expansions** in Australia and elsewhere with sufficient gas reserves and some customer offtake, such as APLNG T2 (FID in 1H12), Tangguh T3 (FID in 2013) QCLNG T3 (FID possibly in 2013) and PNG LNG T3 (FID possibly in late 2013). Later down the line, we would also expect to see an FID on expansion trains at Gorgon (Train 4 and possibly Train 5, once phase 1 is onstream), and Wheatstone Hub.

The attraction from brownfield expansions are the economies of scale that come from sharing basic utilities and infrastructure (up to 30-40% on the downstream costs). There are also other synergies achieved from the sequential building of the trains if the sanctions are taken within 18-24 months of each other – so delays in sanctioning expansions would result in lower economies of scale. Some customers also have a preference for brownfields given their shorter time to market and greater chance of deliverability.

(2) **Newbuild projects** that are lower down the cost curve for various reasons we have cited above, and/or have already started to contract long-term supply under Heads of Agreements. These projects include: Ichthys in Australia for its associated liquids content and proximity to Asian markets (FID in 1Q 2012), Kitimat in Canada (FID in

2012), Cheniere's Sabine Pass in the US Gulf Coast (FID in 2012), Yamal in Russia (FID expected in 1H 2012) and Brass in Nigeria (FID possibly in 2013) given abundant reserves and political support. Proposed projects in Mozambique and Tanzania have potentially lower-cost gas supply. We note Mozambique gas flow rates could be exceptionally strong and the fields are just 30km offshore (vs >200km offshore for Wheatstone). However, we would expect an FID not before the end of 2013 in both countries given insufficient gas in Tanzania (BG/Ophir) and the lack of partner alignment in Mozambique (Eni/Galp/Kogas in Area 4 and APC/Cove/others in Area 1).

… And Which Projects Won't Make It to FID in 2012-13?

We think we are unlikely to see an FID on the following projects in 2012-13, as all of them have one or more of the following issues:

(3) Higher political and/or fiscal risk, such as Shtokman, Sunrise and NLNG T7. Not all the proposed US liquefaction export schemes will be sanctioned if this leads to a political backlash against domestic gas price increases, if these indeed occur (much will depend on the 2012 election).

Greenfield projects with high capital costs (Arrow Energy, Browse—which may end up as backfill gas into the North West Shelf).

Brownfield expansions with insufficient gas reserves as of today, such as Pluto T2 and T3, Snøhvit T2, Sakhalin T3 and Angola T2.

Greenfield projects at very early stages of conception, including all Canadian LNG projects other than Kitimat. However, we believe Shell and XOM's BC LNG projects will also eventually go ahead once they have matured their resource bases.

Among the above projects, we have included Browse and Pluto T2 in our base case and classified all others as "speculative" for the moment. We believe that affordability will deter potential buyers (particularly in Asia) from signing long-term contracts. This may give "speculative" projects time to address some of their issues. Political, fiscal or reserve issues are the most likely reasons to delay a potential FID, in our view.

Exhibit 241: LNG Projects Start-ups, 2011-20E

Nameplate capacity in mtpa

Country	Project	2011E	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	Status
Construction & Possible												
Australia	Pluto LNG		3.2	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	Construction
Angola	Angola LNG		4.0	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	Construction
Algeria	Skikda expansion			3.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	Construction
Papua New Guinea	PNG LNG				2.0	6.6	6.6	6.6	6.6	6.6	6.6	Construction
Algeria	Arzew GL3-Z					3.5	4.7	4.7	4.7	4.7	4.7	Construction
Australia	Gorgon LNG T1-3					7.5	15.0	15.0	15.0	15.0	15.0	Construction
Australia	QC LNG					2.5	7.0	8.3	8.3	8.3	8.3	Construction
Australia	Gladstone LNG					2.0	5.9	7.8	7.8	7.8	7.8	Construction
Indonesia	DS LNG					2.0	2.0	2.0	2.0	2.0	2.0	Construction
Australia	AP LNG (Origin)						4.5	4.5	4.5	4.5	4.5	Construction
Australia	Ichthys LNG						2.1	8.4	8.4	8.4	8.4	Possible
Australia	Pluto LNG T2						2.2	4.3	4.3	4.3	4.3	Possible
US	Sabine Pass						3.7	7.4	7.4	7.4	7.4	Possible
Canada	Kitimat LNG						4.0	5.0	5.0	5.0	7.5	Possible
Australia	Prelude FLNG							3.6	3.6	3.6	3.6	Construction
Australia	Wheatstone							4.5	8.9	8.9	8.9	Construction
Australia	AP LNG T2							4.5	4.5	4.5	4.5	Possible
Australia	QCLNG Train 3							4.3	4.3	4.3	4.3	Possible
Indonesia	Tangguh T3							1.7	3.8	3.8	3.8	Possible
Nigeria	Brass LNG							2.5	10.0	10.0	10.0	Possible
Russia	Yamal LNG								10.0	15.0	15.0	Possible
Australia	Gorgon LNG T4								5.0	5.0	5.0	Possible
Australia	Browse LNG								4.0	10.0	12.0	Possible
Tanzania	Tanzania LNG									7.0	7.0	Possible
Mozambique	Mozambique LNG									4.0	8.0	Possible
Total Construction + Possible			**7.2**	**13.0**	**16.0**	**38.1**	**71.6**	**109.1**	**142.1**	**164.1**	**172.6**	
of which in Construction			**7.2**	**13.0**	**16.0**	**38.1**	**59.7**	**71.0**	**75.4**	**75.4**	**75.4**	
of which Possible							**12.0**	**38.1**	**66.7**	**88.7**	**97.2**	
Speculative												
Russia	Shtokman (Ph 1)							3.3	7.5	7.5	7.5	Speculative
US	Freeport Export							2.4	4.8	7.2	9.6	Speculative
Brazil	Santos FLNG							3.0	3.0	3.0	3.0	Speculative
Equatorial Guinea	EG LNG Train 2								4.4	4.4	4.4	Speculative
Indonesia	Abadi FLNG								1.3	2.5	2.5	Speculative
Australia	Pluto LNG T3								4.3	4.3	4.3	Speculative
Norway	Snøhvit T2								4.2	4.2	4.2	Speculative
US	Lake Charles								5.0	12.0	15.0	Speculative
US	Cove Point								2.5	5.0	5.0	Speculative
Papua New Guinea	PNG LNG T3								1.7	3.3	3.3	Speculative
Nigeria	NLNG Train 7									6.0	8.4	Speculative
Papua New Guinea	Liquid Niugini									2.0	4.0	Speculative
Russia	Sakhalin 2 T3									2.5	5.0	Speculative
Canada	Shell BC										2.5	Speculative
Australia	Sunrise LNG										4.3	Speculative
Iran	Iran LNG										5.3	Speculative
Total Speculative								**8.7**	**38.6**	**63.9**	**88.2**	
Total Additions			**7.2**	**13.0**	**16.0**	**38.1**	**71.6**	**117.7**	**180.7**	**228.0**	**260.8**	

Source: Company data, Credit Suisse estimates.

3. European Gas Market Outlook

Transition for European gas market: We expect the European gas market to be well supplied in natural gas in the medium and long term. LNG should continue to grow its market share, and new supply sources will emerge in the long term (e.g., pipeline imports from Central Asia). In the near term, all eyes are on the outcome of gas price renegotiations between European utilities and Gazprom, as the spread between spot and oil-linked prices is set to widen further, putting pressure on the oil indexation mechanism.

European utilities have excess gas given economic weakness and spare coal-fired power capacity

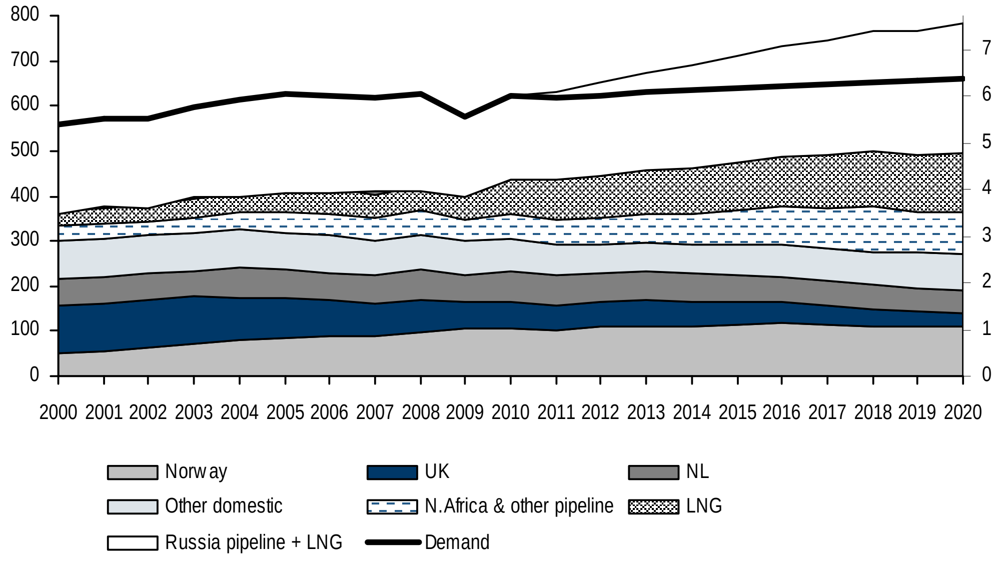
European Gas Supply-Demand Model

Exhibit 242 below illustrates our European gas supply and demand model. As a result of milder weather and a poor economic outlook, the European gas market did not tighten as much as it could have in 2011 given the post-Fukushima tightening in the LNG market and the loss of 9bcm of gas imports from Libya.

Demand has been weak in much of Europe in 2011, with the largest demand reductions seen in North West Europe (-10% ytd in some countries) where demand is not constrained by minimum take-or-pay obligations. The reduction in demand has been driven by the residential sector due to warm weather, and by the power section due to weak electricity demand and low coal prices compared to gas.

Exhibit 242: EU Gas Supply-Demand

in billion cubic meters (LHS) *bcf/d (RHS)*



Source: BP Statistical review, Credit Suisse estimates.

LNG has become the main source of cheaper gas (than Gazprom) in Europe. The volumes of LNG sold in Europe increased by 25% in 2009 and 17% in 2010 y/y. We expect LNG's market share to rise in the long term as new regasification terminals will be commissioned in Europe and new LNG trains will come onstream from 2015. On our estimates, LNG has the potential to gain at least 35% of the European gas market by 2020, providing an alternative to piped gas imports from traditional suppliers, most notably Russia. However, in the near term, we think LNG import growth into Europe could pause. Purely from an LNG arbitrage viewpoint, it will be increasingly difficult for Europe to attract flexible cargoes away from Asia, where the gas shortage is set to grow until 2017.

Gazprom Oil Indexation Increasingly Challenged

We think European utilities, which currently lose money on power produced from Russian gas, will likely try to either break the existing contracts, challenge Gazprom's pricing provisions in arbitration, or at least not to extend contracts expiring in the near term. Turkey's Botas was the first customer that decided not to extend a 6bcm contract on expiry in 2012. Some European customers (e.g., RWE, E.On, PGNiG) are now challenging the oil link in arbitration and we expect a verdict in H2 2012. We think the pressure on Gazprom from the European authorities will keep mounting through further implementation of the Third Energy package.

We expect some change in strategy from Gazprom; however, in the medium term, we believe that Gazprom will continue to pursue its policy of temporary discounts in the expectation that the tightening market will make oil and gas prices recouple. The end of discussions between Gazprom and RWE on a power JV in Europe in late December 2011 appears to indicate that the companies failed to agree on new long-term gas contracts.

In the meantime, European customers will continue to minimise imports from Gazprom. As Gazprom's gas is the most expensive in Europe, its gas would be used only for peak demand if it wasn't for minimum take-or-pay clauses. European utilities still have to buy gas from Gazprom due to take-or-pay obligations, although the latter will not manage to sell gas above minimum legal volumes, on our estimates. Take-or-pay obligations should remain the main factor limiting further LNG import growth in Europe.

European Gas Prices Expected to Remain Range-Bound at $9-11/mcf

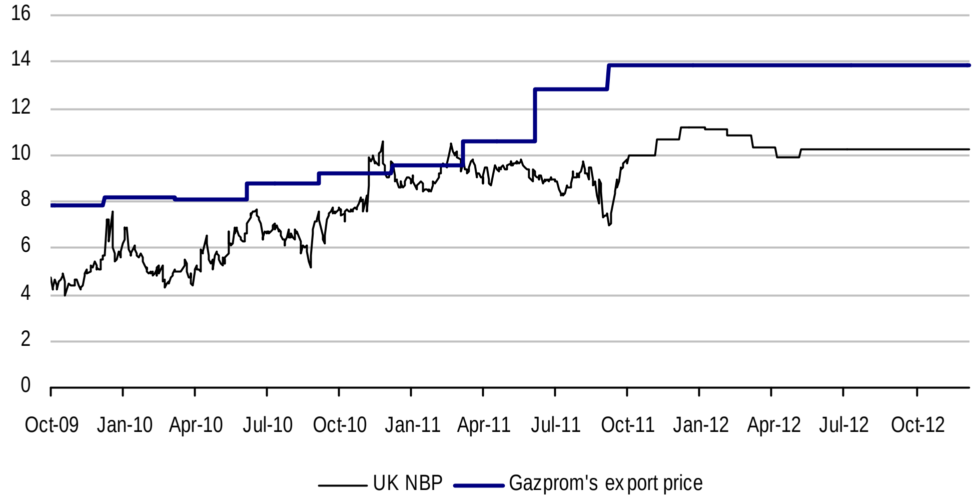
European spot gas prices are influenced by various dynamics and are currently being pulled in opposite directions: long-term oil-linked gas prices of $12-14/mcf (primarily Gazprom and Statoil) are acting as a price ceiling, while coal-gas switching economics are setting a floor of $6.5-7/mcf.

Such a large spread between a price ceiling and floor is unprecedented. This begs the question of whether this gap is sustainable (viability of oil indexation), and to which pricing point (oil-index contracts or coal parity) spot prices will gravitate. In the short to medium term, we expect European spot prices (UK NBP and TTF) to continue to evolve within a range of $9-11/mcf, with temporary fluctuations and possibly spikes to oil-linked prices and due to short-term dislocations in the market and extreme weather conditions.

1. The oil-linked prices are effectively acting as a ceiling for gas prices in Europe, as traditional oil-indexed gas suppliers (most notably Gazprom) are ready to significantly increase export volumes, should European customers demand more gas at oil-indexed prices. Therefore, oil-linked gas from traditional suppliers will tend to be called for only peak demand or only at minimum take-or-pay levels.

Oil prices have stayed above $100/bbl despite global macro issues, and Credit Suisse remains bullish on oil prices in the medium term. Provided Brent prices remain within our mid-term forecast of $105-110/bbl, oil linked gas prices are expected to stay at $14/mmbtu ($500/mcm) for the same period. **This is the first time that gas will be this expensive for European customers for such a long period of time.**

Exhibit 243: Gazprom's Oil-Linked Prices vs. European Spot Prices
in US$/mmbtu



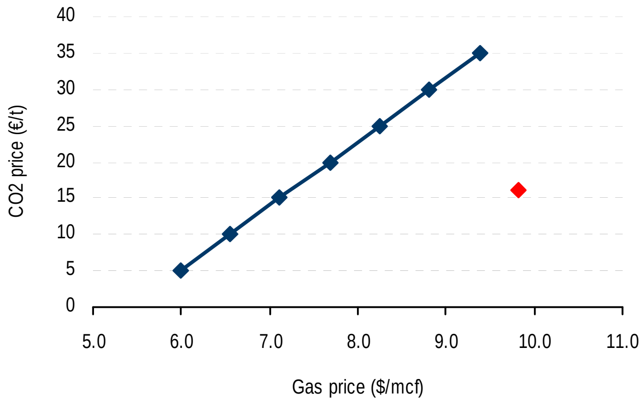
Source: the BLOOMBERG PROFESSIONAL™ service, Company data, Credit Suisse estimates.

2. Coal to gas switching economics provide a floor for European gas prices. Natural gas has to compete against coal, its main substitute in power generation. At current spot gas prices of $9-10/mmbtu, it is still cheaper to burn coal than gas. With current CO2 and gas price levels, either gas prices need to fall or carbon prices need to rise substantially before switching from coal to gas occurs.

The charts in Exhibit 244 and Exhibit 245 illustrate the combinations of commodity and CO2 prices required for gas-coal switching on the *existing* power fleet. The red dots represent current market prices for gas, coal and CO2. At current CO2 prices of €10-15/ton, gas prices would have to fall to $6.5-7/mcf in order to see switching away from coal into gas.

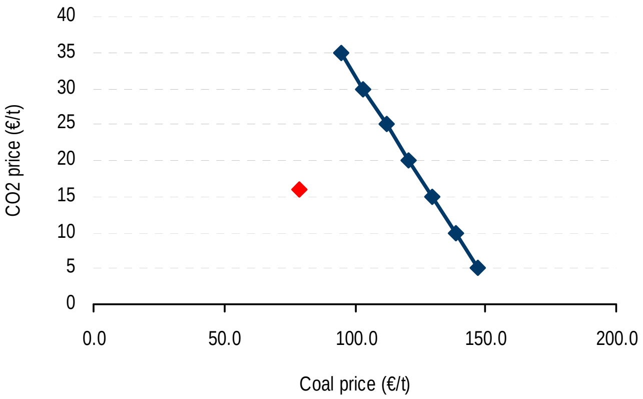
We have already seen some switching from gas into coal in 2011: the share of gas in Europe's generation mix has fallen from 30% in 2009 to 20% in the first 9 months of 2011, while the share of coal has risen from 8% to 15%. We expect this to continue in 2012 as there is available capacity to burn more coal in Europe.

Exhibit 244: Gas Price Required to Switch from Coal to Gas
in $/mcf



Source: Credit Suisse estimates. NB: using CSe 2015 real prices.

Exhibit 245: Coal Price Required to Switch from Coal to Gas



Source: Credit Suisse estimates. NB: using CSe 2015 real prices.

Long-Term Themes in European Gas Markets

- **The German nuclear pull-out is not expected to have a major impact on demand**. We see a potential range of 0–8bcm marginal increase in demand (i.e. only up to c2% European gas demand by 2020E). Our European Utilities team have considered the merit order for European power and Germany's nuclear replacement policy among other swing factors. In the "Green scenario", we assume that Germany manages to meet its target of generating 35% power from renewables by 2020 and builds 95GW of renewables capacity. In the "Fossil fuel scenario" lost nuclear is replaced by a combination of coal and gas, leading to 8bcm of incremental gas demand.

- **Unconventional gas in Europe**: We believe only Poland and Ukraine have potential to become large producers of shale gas by 2020. Poland is heavily dependent on Russia (3/4 of Polish consumption) and is therefore keen to diversify supply. The Polish government has vowed to block any attempts by the EU to enact legislation on shale gas. On the cost side, although it is still early days, we would expect Polish shale gas to be at least 50% more expensive than in the US. However, even at $8/mmbtu it will be more economical to produce shale gas than to buy Russian gas at $14/mmbtu. Drilling activity in Poland should increase in the next few years as companies test their acreage. Ukraine is also struggling to cope with Gazprom's high prices and wants alternatives to gas imports from Russia. We note that Shell, Chevron, Exxon and TNK-BP have expressed interest in exploring for unconventional gas in Ukraine.

- **Central Asian gas imports—finally a reality?** We expect Europe to start importing gas from Central Asia (Azerbaijan, Turkmenistan) via new pipelines from 2017 onwards, whether through Nabucco or a competing pipeline project (e.g., BP's South East Europe). We expect these countries to supply at least 30 bcm a year. Although this represents only 5% of European gas consumption, it should enable Eastern European countries to fully eliminate their dependence on Gazprom and create alternative supply. Turkmenistan is keen to continue to diversify its export markets, even after the start-up of the 30 bcm pipeline to China in July 2011. We believe that Turkmenistan will be able to join the Nabucco project (or another similar pipeline project) by 2017 to export its gas to Europe by building a TransCaspian pipeline.

- **Europe will continue to liberalize its gas market** and ultimately aim to create a Pan-European gas network with more interconnecting pipelines and new LNG regasification terminals. The most significant interconnecting pipeline projects include pipelines between Romania and Hungary, Greece and Bulgaria, Austria and Slovenia. Coupled with the construction of new LNG regasification terminals (in Italy, UK, Spain, France, Germany, Poland, and potentially Croatia, Lithuania and Ukraine), customers should have more leverage in the pricing negotiations with the Russian monopoly. On paper, regasification capacity in Europe could almost double from current levels of 130mtpa if all projects went launched. Storage capacity is also being built, with an extra 59bcm storage capacity is expected to become operational by 2015.

Companies Mentioned *(Price as of 29 Dec 11)*
AES Corporation (AES, $11.88)
Afren Plc (AFRE.L, 86 p, NEUTRAL [V], TP 114.00 p)
Allegheny Energy Inc. (AYE)
Alliant Energy Corp. (LNT, $44.32)
Ameren Corp. (AEE, $33.59)
American Electric Power Co., Inc. (AEP, $41.54, OUTPERFORM, TP $44.00)
Anadarko Petroleum Corp. (APC, $76.19)
Atwood Oceanics, Inc. (ATW, $39.80, NEUTRAL, TP $47.00)
AWE Limited (AWE.AX, A$1.33, NEUTRAL, TP A$1.60)
Baker Hughes Inc. (BHI, $48.17, OUTPERFORM [V], TP $77.00)
Bashneft (BANE.RTS, $42.00, OUTPERFORM, TP $81.00)
BG Group plc (BG.L, 1371 p, OUTPERFORM, TP 1,730.00 p)
Black Hills Corporation (BKH, $34.15, OUTPERFORM, TP $35.00)
Boardwalk Pipeline Partners, LP (BWP, $27.64, OUTPERFORM, TP $35.00)
BP (BP.N, $42.63, OUTPERFORM, TP $54.00)
BP (BP.L, 461 p, OUTPERFORM, TP 575.00 p)
Cairn Energy (CNE.L, 267 p, NEUTRAL, TP 357.00 p)
Cameron International Corp. (CAM, $48.65, OUTPERFORM, TP $71.00)
Canadian Natural Resources Limited (CNQ.TO, C$37.48, OUTPERFORM, TP C$56.00)
Capital Power Corporation (CPX.TO, C$25.15, OUTPERFORM, TP C$28.00)
Cenovus Energy Inc. (CVE.TO, C$33.23, NEUTRAL, TP C$40.00)
CGGVeritas (GEPH.PA, Eu17.95, NEUTRAL [V], TP Eu30.00)
Chesapeake Energy Corp. (CHK, $22.73)
Chevron Corp. (CVX, $107.47, OUTPERFORM, TP $130.00)
China Oilfield Services Ltd (2883.HK, HK$12.12, OUTPERFORM, TP HK$16.80)
China Petroleum & Chemical Corporation - H (0386.HK, HK$8.17, NEUTRAL, TP HK$8.40)
CMS Energy (CMS, $22.35, OUTPERFORM, TP $25.00)
CNOOC Ltd (0883.HK, HK$13.58, OUTPERFORM, TP HK$15.95)
Cobalt International Energy (CIE, $15.62, OUTPERFORM [V], TP $17.00)
Connacher Oil & Gas (CLL.TO, C$0.76, OUTPERFORM [V], TP C$1.25)
ConocoPhillips (COP, $72.87, RESTRICTED)
Crescent Point Energy Corp. (CPG.TO, C$45.00, NEUTRAL, TP C$43.00)
DCP Midstream Partners, LP (DPM, $47.55, OUTPERFORM, TP $47.00)
Delek US Holdings, Inc. (DK, $11.39, NEUTRAL [V], TP $16.00)
Denbury Resources (DNR, $15.18)
Det norske oljeselskap ASA (DETNOR.OL, NKr87.00, OUTPERFORM [V], TP NKr120.00)
Devon Energy Corp (DVN, $62.29)
Diamond Offshore (DO, $56.00, UNDERPERFORM, TP $67.00)
DNO ASA (DNO.OL, NKr7.43, OUTPERFORM [V], TP NKr9.40)
Dominion Resources (D, $53.53, NEUTRAL, TP $58.00)
DPL (DPL, $30.19)
DTE Energy (DTE, $55.02, OUTPERFORM, TP $59.00)
Duke Energy (DUK, $22.06, NEUTRAL, TP $22.00)
Edison International (EIX, $41.52, OUTPERFORM, TP $48.00)
El Paso Pipeline Partners, LP (EPB, $34.61, OUTPERFORM, TP $41.00)
Enbridge Energy Partners, LP (EEP, $32.89)
Enbridge Inc. (ENB.TO, C$37.81, NEUTRAL, TP C$35.00)
EnCana Corp. (ECA, $18.35, OUTPERFORM, TP $27.00)
Energy Transfer Partners, L.P. (ETP, $45.62, RESTRICTED)
Energy XXI (EXXI, $31.62, OUTPERFORM [V], TP $40.00)
ENI (E.N, $41.14, NEUTRAL, TP $52.00)
ENI (ENI.MI, Eu15.78, NEUTRAL, TP Eu18.50)
Ensco Plc. (ESV, $47.54, OUTPERFORM, TP $71.00)
Entergy Corporation (ETR, $73.65, NEUTRAL, TP $75.00)
Enterprise Products Partners, LP (EPD, $46.19, OUTPERFORM, TP $47.00)
EOG Resources (EOG, $98.05)
EQT Corporation (EQT, $55.17)
Eurasia Drilling Co (EDCLq.L, $23.00, OUTPERFORM [V], TP $32.52)
Exelon Corporation (EXC, $43.71, RESTRICTED)
ExxonMobil Corporation (XOM, $85.27, NEUTRAL, TP $95.00)
FirstEnergy (FE, $45.13, OUTPERFORM, TP $43.00)
FMC Technologies, Inc. (FTI, $52.15, NEUTRAL, TP $45.00)

Forest Oil (FST, $13.26, OUTPERFORM [V], TP $18.00)
Frontier Oil Corporation (FTO)
Galp Energia SGPS (GALP.LS, Eu11.40, OUTPERFORM, TP Eu15.00)
Gazprom (GAZP.RTS, $5.18, NEUTRAL, TP $5.70)
Gazprom Neft (SIBN.RTS, $4.59, NEUTRAL, TP $5.71)
Genel Energy plc (GENL.L, 781 p, OUTPERFORM [V], TP 1,093.00 p)
Great Plains Energy (GXP, $21.93)
Halliburton (HAL, $33.79, OUTPERFORM [V], TP $58.00)
Helmerich & Payne, Inc. (HP, $58.26, NEUTRAL, TP $68.00)
Hercules Offshore (HERO, $4.44, OUTPERFORM [V], TP $6.50)
Heritage Oil (HOIL.L, 184 p)
Hess Corporation (HES, $56.47, OUTPERFORM, TP $115.00)
Holly Corp. (HOC, $23.20)
Holly Energy Partners, L.P. (HEP, $53.54)
Husky Energy Inc. (HSE.TO, C$24.33, NEUTRAL, TP C$28.00)
Imperial Oil Ltd (IMO.TO, C$44.99, NEUTRAL, TP C$52.00)
INPEX Corporation (1605, ¥483,000, OUTPERFORM, TP ¥700,000, MARKET WEIGHT)
Karoon Gas (KAR.AX, A$4.70, OUTPERFORM [V], TP A$7.65)
KazMunaiGas EP (KMGq.L, $14.93, NEUTRAL, TP $30.75)
Kinder Morgan Energy Partners, L.P. (KMP, $84.24, NEUTRAL, TP $77.00)
Kosmos Energy Ltd (KOS, $12.27, OUTPERFORM [V], TP $25.00)
LUKOIL (LKOH.RTS, $51.20, NEUTRAL, TP $56.70)
Lundin Petroleum (LUPE.ST, SKr167.60, NEUTRAL, TP SKr187.00)
Marathon Oil Corp (MRO, $29.30, NEUTRAL, TP $36.00)
Marathon Petroleum Corporation (MPC, $33.28, OUTPERFORM, TP $63.00)
Minnesota Power Inc. (ALE, $42.40)
MOL (MOLB.BU, HUF17,725.00, OUTPERFORM, TP HUF22,100.00)
Murphy Oil Corp. (MUR, $55.70)
Nabors Industries, Ltd. (NBR, $17.59, OUTPERFORM [V], TP $27.00)
National Oilwell Varco (NOV, $67.87, OUTPERFORM, TP $87.00)
Neste (NES1V.HE, Eu7.74, OUTPERFORM, TP Eu11.00)
Newfield Exploration Co. (NFX, $37.95)
Nexen Inc. (NXY.TO, C$15.61, NEUTRAL, TP C$24.00)
NextEra Energy Inc. (NEE, $61.08, OUTPERFORM, TP $58.00)
Noble Corporation (NE, $30.72, OUTPERFORM, TP $49.00)
Noble Energy (NBL, $96.03)
NOVATEK (NVTK.RTS, $12.15, OUTPERFORM, TP $17.10)
NV Energy Inc (NVE, $16.42, NEUTRAL, TP $17.00)
Occidental Petroleum (OXY, $93.72, OUTPERFORM, TP $135.00)
Oceaneering Intl, Inc. (OII, $46.76, NEUTRAL, TP $48.00)
OGE (OGE, $56.82)
Oil & Natural Gas Corporation Limited (ONGC.BO, Rs258.45, NEUTRAL, TP Rs337.00)
Oil Search (OSH.AX, A$6.26, OUTPERFORM, TP A$7.40)
Oil States International (OIS, $75.57, OUTPERFORM, TP $110.00)
OMV (OMVV.VI, Eu23.44, UNDERPERFORM, TP Eu25.00)
Ophir Energy plc (OPHR.L, 281 p, OUTPERFORM, TP 510.00 p)
Origin Energy (ORG.AX, A$13.25, OUTPERFORM, TP A$16.90)
Pacific Northern Gas Ltd. (PNG.TO, C$36.71, NEUTRAL, TP C$36.75)
Patterson-UTI Energy, Inc. (PTEN, $19.91, OUTPERFORM, TP $29.00)
PDC Energy (PETD, $35.23, OUTPERFORM [V], TP $41.00)
Penn West Exploration (PWT.TO, C$20.16, OUTPERFORM, TP C$27.00)
PetroBakken Energy Ltd. (PBN.TO, C$12.81, OUTPERFORM [V], TP C$17.00)
PetroChina - H (0857.HK, HK$9.71, NEUTRAL, TP HK$10.50)
Petrofac (PFC.L, 1446 p, OUTPERFORM, TP 1,500.00 p)
PetroHawk Energy Corp. (HK)
Pinnacle West Capital Corp. (PNW, $48.59, NEUTRAL, TP $52.00)
Pioneer Natural Resources (PXD, $88.97)
PKN Orlen (PKNA.WA, PLN33.76, OUTPERFORM, TP PLN59.00)
Plains Exploration & Production Co. (PXP, $36.49)
Precision Drilling Corporation (PDS, $10.31, OUTPERFORM [V], TP $15.42)
Premier Oil (PMO.L, 361 p, OUTPERFORM, TP 490.00 p)
Pride International Inc. (PDE)
Progress Energy (PGN, $56.23, NEUTRAL, TP $52.00)
Public Svc Ent (PEG, $32.94, OUTPERFORM, TP $36.00)
Quicksilver Resources, Inc. (KWK, $6.84, RESTRICTED [V])

Range Resources (RRC, $62.49, OUTPERFORM, TP $77.00)
Repsol YPF SA (REP.MC, Eu23.50, OUTPERFORM, TP Eu27.00)
Rosetta Resources Inc. (ROSE, $43.81, OUTPERFORM [V], TP $68.00)
Rosneft (ROSN.RTS, $7.05, UNDERPERFORM, TP $6.80)
Rowan Companies (RDC, $31.02, NEUTRAL, TP $42.00)
Royal Dutch Shell plc (RDSa.L, 2377 p, OUTPERFORM, TP 2,750.00 p)
Royal Dutch Shell PLC (ADR) (RDSa.N, $73.12, OUTPERFORM, TP $87.00)
Saipem (SPMI.MI, Eu32.70, UNDERPERFORM, TP Eu38.00)
SandRidge Energy, Inc. (SD, $8.22)
Santos (STO.AX, A$12.32, NEUTRAL, TP A$14.65)
Saras (SRS.MI, Eu0.94, UNDERPERFORM [V], TP Eu1.20)
Sasol Limited (SOLJ.J, R380.9, OUTPERFORM, TP R457)
SBM Offshore (SBMO.AS, Eu15.99, OUTPERFORM, TP Eu21.00)
SCANA Corporation (SCG, $45.34)
Schlumberger (SLB, $67.41, OUTPERFORM, TP $99.00)
Seadrill (SDRL, NKr200.50, NEUTRAL, TP NKr200.00)
SOCO International (SIA.L, 293 p, NEUTRAL, TP 313.00 p)
Southern Company (SO, $46.59, OUTPERFORM, TP $49.00)
Spectra Energy Corp (SE, $30.85)
Statoil (STL.OL, NKr153.00, NEUTRAL, TP NKr158.00)
Statoil (STO.N, $25.63, NEUTRAL, TP $27.00)
Suncor Energy (SU.TO, C$29.12, OUTPERFORM, TP C$50.00)
Surgutneftegaz (SNGS.RTS, $0.88, UNDERPERFORM, TP $0.92)
Swift Energy Co. (SFY, $30.48, OUTPERFORM, TP $46.00)
Tap Oil (TAP.AX, A$0.60, OUTPERFORM [V], TP A$0.95)
Targa Resources Partners LP (NGLS, $37.45, OUTPERFORM, TP $42.00)
Tatneft (TATN.RTS, $4.75)
Technip (TECF.PA, Eu72.52, NEUTRAL, TP Eu69.00)
Tesoro Corp. (TSO, $23.34, NEUTRAL [V], TP $35.00)
Tidewater (TDW, $49.20, OUTPERFORM, TP $56.00)
TNK-BP (TNBPI.RTS, $3.00)
Total (TOT.N, $50.81, NEUTRAL, TP $61.00)
Total (TOTF.PA, Eu39.26, NEUTRAL, TP Eu45.00)
TransCanada Corp. (TRP.TO, C$44.16, NEUTRAL, TP C$44.00)
Transocean Inc. (RIG, $38.56, NEUTRAL [V], TP $55.00)
Tullow Oil (TLW.L, 1380 p, OUTPERFORM, TP 1,776.00 p)
Tupras (TUPRS.IS, TRY40.20, OUTPERFORM, TP TRY52.40)
Ultra Petroleum Corp. (UPL, $30.21)
Valero Energy Corporation (VLO, $20.75, OUTPERFORM, TP $40.00)
Vallourec (VLLP.PA, Eu49.30, OUTPERFORM, TP Eu60.00)
Venoco, Inc. (VQ, $6.65, NEUTRAL [V], TP $10.00)
Weatherford International, Inc. (WFT, $14.20, NEUTRAL [V], TP $20.00)
Wellstream (WSML.L, 0 p)
Western Refining Inc. (WNR, $13.20, OUTPERFORM [V], TP $20.50)
Whiting Petroleum Corp. (WLL, $46.33, OUTPERFORM, TP $69.00)
Wood Group (John) (WG.L, 639 p, RESTRICTED)
Woodside Petroleum (WPL.AX, A$30.99, OUTPERFORM, TP A$42.50)
YPF Sociedad Anonima (YPF, $35.46, OUTPERFORM [V], TP $50.00)

Disclosure Appendix

Important Global Disclosures

I, Edward Westlake, certify that (1) the views expressed in this report accurately reflect my personal views about all of the subject companies and securities and (2) no part of my compensation was, is or will be directly or indirectly related to the specific recommendations or views expressed in this report.

The analyst(s) responsible for preparing this research report received compensation that is based upon various factors including Credit Suisse's total revenues, a portion of which are generated by Credit Suisse's investment banking activities.

Analysts' stock ratings are defined as follows:

Outperform (O): The stock's total return is expected to outperform the relevant benchmark* by at least 10-15% (or more, depending on perceived risk) over the next 12 months.

Neutral (N): The stock's total return is expected to be in line with the relevant benchmark* (range of ±10-15%) over the next 12 months.

Underperform (U): The stock's total return is expected to underperform the relevant benchmark* by 10-15% or more over the next 12 months.

Relevant benchmark by region: As of 29th May 2009, Australia, New Zealand, U.S. and Canadian ratings are based on (1) a stock's absolute total return potential to its current share price and (2) the relative attractiveness of a stock's total return potential within an analyst's coverage universe,* *with Outperforms representing the most attractive, Neutrals the less attractive, and Underperforms the least attractive investment opportunities. Some U.S. and Canadian ratings may fall outside the absolute total return ranges defined above, depending on market conditions and industry factors. For Latin American, Japanese, and non-Japan Asia stocks, ratings are based on a stock's total return relative to the average total return of the relevant country or regional benchmark; for European stocks, ratings are based on a stock's total return relative to the analyst's coverage universe**. For Australian and New Zealand stocks, 12-month rolling yield is incorporated in the absolute total return calculation and a 15% and a 7.5% threshold replace the 10-15% level in the Outperform and Underperform stock rating definitions, respectively. The 15% and 7.5% thresholds replace the +10-15% and -10-15% levels in the Neutral stock rating definition, respectively.*

***An analyst's coverage universe consists of all companies covered by the analyst within the relevant sector.*

Restricted (R): In certain circumstances, Credit Suisse policy and/or applicable law and regulations preclude certain types of communications, including an investment recommendation, during the course of Credit Suisse's engagement in an investment banking transaction and in certain other circumstances.

Volatility Indicator [V]: A stock is defined as volatile if the stock price has moved up or down by 20% or more in a month in at least 8 of the past 24 months or the analyst expects significant volatility going forward.

Analysts' coverage universe weightings are distinct from analysts' stock ratings and are based on the expected performance of an analyst's coverage universe* versus the relevant broad market benchmark**:

Overweight: Industry expected to outperform the relevant broad market benchmark over the next 12 months.

Market Weight: Industry expected to perform in-line with the relevant broad market benchmark over the next 12 months.

Underweight: Industry expected to underperform the relevant broad market benchmark over the next 12 months.

**An analyst's coverage universe consists of all companies covered by the analyst within the relevant sector.*

***The broad market benchmark is based on the expected return of the local market index (e.g., the S&P 500 in the U.S.) over the next 12 months.*

Credit Suisse's distribution of stock ratings (and banking clients) is:

	Global Ratings Distribution	
Outperform/Buy*	47%	(61% banking clients)
Neutral/Hold*	40%	(57% banking clients)
Underperform/Sell*	10%	(51% banking clients)
Restricted	2%	

**For purposes of the NYSE and NASD ratings distribution disclosure requirements, our stock ratings of Outperform, Neutral, and Underperform most closely correspond to Buy, Hold, and Sell, respectively; however, the meanings are not the same, as our stock ratings are determined on a relative basis. (Please refer to definitions above.) An investor's decision to buy or sell a security should be based on investment objectives, current holdings, and other individual factors.*

Credit Suisse's policy is to update research reports as it deems appropriate, based on developments with the subject company, the sector or the market that may have a material impact on the research views or opinions stated herein.

Credit Suisse's policy is only to publish investment research that is impartial, independent, clear, fair and not misleading. For more detail please refer to Credit Suisse's Policies for Managing Conflicts of Interest in connection with Investment Research: http://www.csfb.com/research-and-analytics/disclaimer/managing_conflicts_disclaimer.html

Credit Suisse does not provide any tax advice. Any statement herein regarding any US federal tax is not intended or written to be used, and cannot be used, by any taxpayer for the purposes of avoiding any penalties.

Important Regional Disclosures

Singapore recipients should contact a Singapore financial adviser for any matters arising from this research report.

Restrictions on certain Canadian securities are indicated by the following abbreviations: NVS--Non-Voting shares; RVS--Restricted Voting Shares; SVS--Subordinate Voting Shares.

Individuals receiving this report from a Canadian investment dealer that is not affiliated with Credit Suisse should be advised that this report may not contain regulatory disclosures the non-affiliated Canadian investment dealer would be required to make if this were its own report.

For Credit Suisse Securities (Canada), Inc.'s policies and procedures regarding the dissemination of equity research, please visit http://www.csfb.com/legal_terms/canada_research_policy.shtml.

Credit Suisse Securities (Europe) Limited acts as broker to DK, KMGq.L, WSML.L, WG.L.

The following disclosed European company/ies have estimates that comply with IFRS: BG.L, BP.L, CNE.L, DK, ENI.MI, XOM, GAZP.RTS, SIBN.RTS, KMGq.L, LKOH.RTS, MOLB.BU, NES1V.HE, NVTK.RTS, OMVV.VI, PFC.L, PKNA.WA, PMO.L, REP.MC, ROSN.RTS, RDSa.L, SPMI.MI, SBMO.AS, SDRL, STL.OL, SNGS.RTS, TECF.PA, TOTF.PA, TLW.L, TUPRS.IS, VLLP.PA, WG.L.

As of the date of this report, Credit Suisse acts as a market maker or liquidity provider in the equities securities that are the subject of this report.

Principal is not guaranteed in the case of equities because equity prices are variable.

Commission is the commission rate or the amount agreed with a customer when setting up an account or at anytime after that.

CS may have issued a Trade Alert regarding this security. Trade Alerts are short term trading opportunities identified by an analyst on the basis of market events and catalysts, while stock ratings reflect an analyst's investment recommendations based on expected total return over a 12-month period relative to the relevant coverage universe. Because Trade Alerts and stock ratings reflect different assumptions and analytical methods, Trade Alerts may differ directionally from the analyst's stock rating.

The author(s) of this report maintains a CS Model Portfolio that he/she regularly adjusts. The security or securities discussed in this report may be a component of the CS Model Portfolio and subject to such adjustments (which, given the composition of the CS Model Portfolio as a whole, may differ from the recommendation in this report, as well as opportunities or strategies identified in Trading Alerts concerning the same security). The CS Model Portfolio and important disclosures about it are available at www.credit-suisse.com/ti.

Taiwanese Disclosures: Reports written by Taiwan-based analysts on non-Taiwan listed companies are not considered recommendations to buy or sell securities under Taiwan Stock Exchange Operational Regulations Governing Securities Firms Recommending Trades in Securities to Customers.

To the extent this is a report authored in whole or in part by a non-U.S. analyst and is made available in the U.S., the following are important disclosures regarding any non-U.S. analyst contributors:

The non-U.S. research analysts listed below (if any) are not registered/qualified as research analysts with FINRA. The non-U.S. research analysts listed below may not be associated persons of CSSU and therefore may not be subject to the NASD Rule 2711 and NYSE Rule 472 restrictions on communications with a subject company, public appearances and trading securities held by a research analyst account.

- Sandra McCullagh, non-U.S. analyst, is a research analyst employed by Credit Suisse Equities (Australia) Limited.
- Kim Fustier, non-U.S. analyst, is a research analyst employed by Credit Suisse Securities (Europe) Limited.
- Thomas Adolff, non-U.S. analyst, is a research analyst employed by Credit Suisse Securities (Europe) Limited.
- Brian Dutton, non-U.S. analyst, is a research analyst employed by Credit Suisse Securities (Canada), Inc..
- David Hewitt, non-U.S. analyst, is a research analyst employed by Credit Suisse AG, Singapore Branch.
- Andrey Ovchinnikov, non-U.S. analyst, is a research analyst employed by Credit Suisse Securities (Europe) Limited.
- Jason Turner, non-U.S. analyst, is a research analyst employed by Credit Suisse Securities (Europe) Limited.
- Emerson Leite, CFA, non-U.S. analyst, is a research analyst employed by Banco de Investimentos Credit Suisse (Brasil) S.A. or its affiliates.

Important Credit Suisse HOLT Disclosures

With respect to the analysis in this report based on the Credit Suisse HOLT methodology, Credit Suisse certifies that (1) the views expressed in this report accurately reflect the Credit Suisse HOLT methodology and (2) no part of the Firm's compensation was, is, or will be directly related to the specific views disclosed in this report.

The Credit Suisse HOLT methodology does not assign ratings to a security. It is an analytical tool that involves use of a set of proprietary quantitative algorithms and warranted value calculations, collectively called the Credit Suisse HOLT valuation model, that are consistently applied to all the companies included in its database. Third-party data (including consensus earnings estimates) are systematically translated into a number of default variables and incorporated into the algorithms available in the Credit Suisse HOLT valuation model. The source financial statement, pricing, and earnings data provided by outside data vendors are subject to quality control and may also be adjusted to more closely measure the underlying economics of firm performance. These adjustments provide consistency when analyzing a single company across time, or analyzing multiple companies across industries or national borders. The default scenario that is produced by the Credit Suisse HOLT valuation model establishes the baseline valuation for a security, and a user then may adjust the default variables to produce alternative scenarios, any of which could occur. Additional information about the Credit Suisse HOLT methodology is available on request.

The Credit Suisse HOLT methodology does not assign a price target to a security. The default scenario that is produced by the Credit Suisse HOLT valuation model establishes a warranted price for a security, and as the third-party data are updated, the warranted price may also change. The default variables may also be adjusted to produce alternative warranted prices, any of which could occur.

CFROI®, HOLT, HOLTfolio, HOLTSelect, ValueSearch, AggreGator, Signal Flag and "Powered by HOLT" are trademarks or service marks or registered trademarks or registered service marks of Credit Suisse or its affiliates in the United States and other countries. HOLT is a corporate performance and valuation advisory service of Credit Suisse.

Additional information about the Credit Suisse HOLT methodology is available on request.

For Credit Suisse disclosure information on other companies mentioned in this report, please visit the website at www.credit-suisse.com/researchdisclosures or call +1 (877) 291-2683.

Disclaimers continue on next page.

03 January 2012
Global
Equity Research

This report is not directed to, or intended for distribution to or use by, any person or entity who is a citizen or resident of or located in any locality, state, country or other jurisdiction where such distribution, publication, availability or use would be contrary to law or regulation or which would subject Credit Suisse AG, the Swiss bank, or its subsidiaries or its affiliates ("CS") to any registration or licensing requirement within such jurisdiction. All material presented in this report, unless specifically indicated otherwise, is under copyright to CS. None of the material, nor its content, nor any copy of it, may be altered in any way, transmitted to, copied or distributed to any other party, without the prior express written permission of CS. All trademarks, service marks and logos used in this report are trademarks or service marks or registered trademarks or service marks of CS or its affiliates.

The information, tools and material presented in this report are provided to you for information purposes only and are not to be used or considered as an offer or the solicitation of an offer to sell or to buy or subscribe for securities or other financial instruments. CS may not have taken any steps to ensure that the securities referred to in this report are suitable for any particular investor. CS will not treat recipients as its customers by virtue of their receiving the report. The investments or services contained or referred to in this report may not be suitable for you and it is recommended that you consult an independent investment advisor if you are in doubt about such investments or investment services. Nothing in this report constitutes investment, legal, accounting or tax advice or a representation that any investment or strategy is suitable or appropriate to your individual circumstances or otherwise constitutes a personal recommendation to you. CS does not offer advice on the tax consequences of investment and you are advised to contact an independent tax adviser. Please note in particular that the bases and levels of taxation may change.

CS believes the information and opinions in the Disclosure Appendix of this report are accurate and complete. Information and opinions presented in the other sections of the report were obtained or derived from sources CS believes are reliable, but CS makes no representations as to their accuracy or completeness. Additional information is available upon request. CS accepts no liability for loss arising from the use of the material presented in this report, except that this exclusion of liability does not apply to the extent that liability arises under specific statutes or regulations applicable to CS. This report is not to be relied upon in substitution for the exercise of independent judgment. CS may have issued, and may in the future issue, a trading call regarding this security. Trading calls are short term trading opportunities based on market events and catalysts, while stock ratings reflect investment recommendations based on expected total return over a 12-month period as defined in the disclosure section. Because trading calls and stock ratings reflect different assumptions and analytical methods, trading calls may differ directionally from the stock rating. In addition, CS may have issued, and may in the future issue, other reports that are inconsistent with, and reach different conclusions from, the information presented in this report. Those reports reflect the different assumptions, views and analytical methods of the analysts who prepared them and CS is under no obligation to ensure that such other reports are brought to the attention of any recipient of this report. CS is involved in many businesses that relate to companies mentioned in this report. These businesses include specialized trading, risk arbitrage, market making, and other proprietary trading.

Past performance should not be taken as an indication or guarantee of future performance, and no representation or warranty, express or implied, is made regarding future performance. Information, opinions and estimates contained in this report reflect a judgement at its original date of publication by CS and are subject to change without notice. The price, value of and income from any of the securities or financial instruments mentioned in this report can fall as well as rise. The value of securities and financial instruments is subject to exchange rate fluctuation that may have a positive or adverse effect on the price or income of such securities or financial instruments. Investors in securities such as ADR's, the values of which are influenced by currency volatility, effectively assume this risk.

Structured securities are complex instruments, typically involve a high degree of risk and are intended for sale only to sophisticated investors who are capable of understanding and assuming the risks involved. The market value of any structured security may be affected by changes in economic, financial and political factors (including, but not limited to, spot and forward interest and exchange rates), time to maturity, market conditions and volatility, and the credit quality of any issuer or reference issuer. Any investor interested in purchasing a structured product should conduct their own investigation and analysis of the product and consult with their own professional advisers as to the risks involved in making such a purchase.

Some investments discussed in this report have a high level of volatility. High volatility investments may experience sudden and large falls in their value causing losses when that investment is realised. Those losses may equal your original investment. Indeed, in the case of some investments the potential losses may exceed the amount of initial investment, in such circumstances you may be required to pay more money to support those losses. Income yields from investments may fluctuate and, in consequence, initial capital paid to make the investment may be used as part of that income yield. Some investments may not be readily realisable and it may be difficult to sell or realise those investments, similarly it may prove difficult for you to obtain reliable information about the value, or risks, to which such an investment is exposed.

This report may provide the addresses of, or contain hyperlinks to, websites. Except to the extent to which the report refers to website material of CS, CS has not reviewed the linked site and takes no responsibility for the content contained therein. Such address or hyperlink (including addresses or hyperlinks to CS's own website material) is provided solely for your convenience and information and the content of the linked site does not in any way form part of this document. Accessing such website or following such link through this report or CS's website shall be at your own risk.

This report is issued and distributed in Europe (except Switzerland) by Credit Suisse Securities (Europe) Limited, One Cabot Square, London E14 4QJ, England, which is regulated in the United Kingdom by The Financial Services Authority ("FSA"). This report is being distributed in Germany by Credit Suisse Securities (Europe) Limited Niederlassung Frankfurt am Main regulated by the Bundesanstalt fuer Finanzdienstleistungsaufsicht ("BaFin"). This report is being distributed in the United States by Credit Suisse Securities (USA) LLC ; in Switzerland by Credit Suisse AG; in Canada by Credit Suisse Securities (Canada), Inc.; in Brazil by Banco de Investimentos Credit Suisse (Brasil) S.A. or its affiliates; in Mexico by Banco Credit Suisse (México), S.A. (transactions related to the securities mentioned in this report will only be effected in compliance with applicable regulation); in Japan by Credit Suisse Securities (Japan) Limited, Financial Instrument Firm, Director-General of Kanto Local Finance Bureau (Kinsho) No. 66, a member of Japan Securities Dealers Association, The Financial Futures Association of Japan, Japan Securities Investment Advisers Association, Type II Financial Instruments Firms Association; elsewhere in Asia/Pacific by whichever of the following is the appropriately authorised entity in the relevant jurisdiction: Credit Suisse (Hong Kong) Limited, Credit Suisse Equities (Australia) Limited , Credit Suisse Securities (Thailand) Limited, Credit Suisse Securities (Malaysia) Sdn Bhd, Credit Suisse AG, Singapore Branch, Credit Suisse Securities (India) Private Limited regulated by the Securities and Exchange Board of India (registration Nos. INB230970637; INF230970637; INB010970631; INF010970631), having registered address at 9th Floor, Ceejay House,Dr.A.B. Road, Worli, Mumbai - 18, India, T- +91-22 6777 3777, Credit Suisse Securities (Europe) Limited, Seoul Branch, Credit Suisse AG, Taipei Securities Branch, PT Credit Suisse Securities Indonesia, Credit Suisse Securities (Philippines) Inc., and elsewhere in the world by the relevant authorised affiliate of the above. Research on Taiwanese securities produced by Credit Suisse AG, Taipei Securities Branch has been prepared by a registered Senior Business Person. Research provided to residents of Malaysia is authorised by the Head of Research for Credit Suisse Securities (Malaysia) Sdn. Bhd., to whom they should direct any queries on +603 2723 2020.

In jurisdictions where CS is not already registered or licensed to trade in securities, transactions will only be effected in accordance with applicable securities legislation, which will vary from jurisdiction to jurisdiction and may require that the trade be made in accordance with applicable exemptions from registration or licensing requirements. Non-U.S. customers wishing to effect a transaction should contact a CS entity in their local jurisdiction unless governing law permits otherwise. U.S. customers wishing to effect a transaction should do so only by contacting a representative at Credit Suisse Securities (USA) LLC in the U.S.

Please note that this report was originally prepared and issued by CS for distribution to their market professional and institutional investor customers. Recipients who are not market professional or institutional investor customers of CS should seek the advice of their independent financial advisor prior to taking any investment decision based on this report or for any necessary explanation of its contents. This research may relate to investments or services of a person outside of the UK or to other matters which are not regulated by the FSA or in respect of which the protections of the FSA for private customers and/or the UK compensation scheme may not be available, and further details as to where this may be the case are available upon request in respect of this report.

Any Nielsen Media Research material contained in this report represents Nielsen Media Research's estimates and does not represent facts. NMR has neither reviewed nor approved this report and/or any of the statements made herein.

If this report is being distributed by a financial institution other than Credit Suisse AG, or its affiliates, that financial institution is solely responsible for distribution. Clients of that institution should contact that institution to effect a transaction in the securities mentioned in this report or require further information. This report does not constitute investment advice by Credit Suisse to the clients of the distributing financial institution, and neither Credit Suisse AG, its affiliates, and their respective officers, directors and employees accept any liability whatsoever for any direct or consequential loss arising from their use of this report or its content.

Copyright 2012 CREDIT SUISSE AG and/or its affiliates. All rights reserved.

CREDIT SUISSE SECURITIES (USA) LLC
United States of America: +1 (212) 325-2000